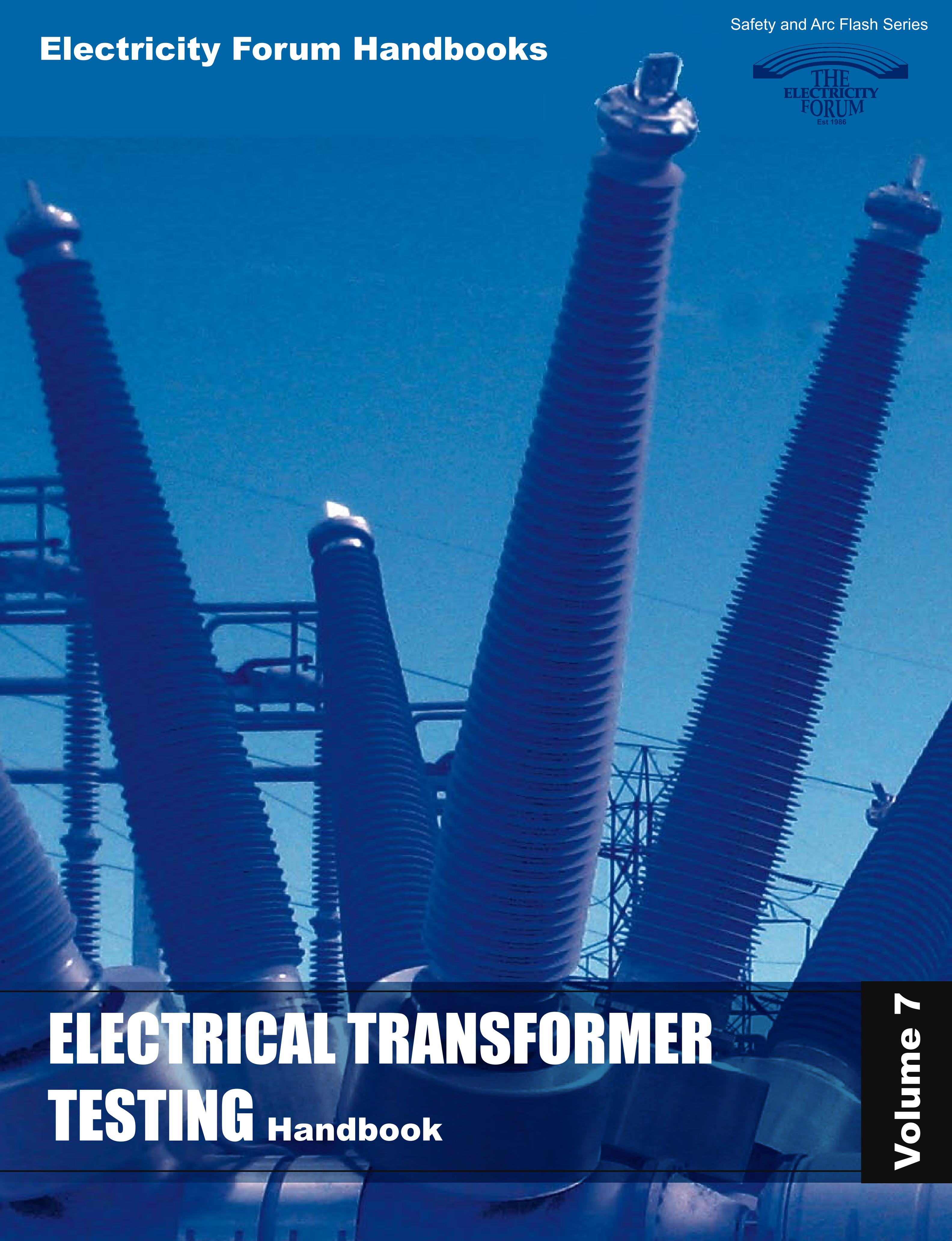

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# ELECTRICAL TRANSFORMER TESTING Handbook

Volume 7

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# ELECTRICAL TRANSFORMER TESTING

## Handbook

## Volume 7

## Published by The Electricity Forum

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# ELECTRICAL TRANSFORMER TESTING

## Handbook

## Volume 7

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The Electricity Forum
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ISBN-978-1-897474-25-9
The Electricity Forum
218 - 1885 Clements Road,
Pickering, ON L1W 3V4

Printed in Canada

© The Electricity Forum 2010

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# Transformer /Line Loss Calculations

**Schneider Electric**

| Element | Definition |
|---|---|
| $\frac{r}{l}$ | Per unit length resistance |
| $\frac{x}{l}$ | Per unit length reactance |
| $L$ | Total length in units |
| $R$ | Resistive component |
| $Z$ | Impedance |
| $P_{loss}$ | Active power loss |
| $X$ | Reactive component |
| $Q_{loss}$ | Reactive power loss |

## OVERVIEW

Loss Compensation is used when a meter's actual location is different from the electrical location where change of ownership occurs; for example, where meters are connected on the low-voltage side of power transformers when the ownership change occurs on the high-voltage side of the transformer. This physical separation between meter and actual billing point results in measurable losses. Compensating for this loss - Loss Compensation - is the means of correcting this meter reading.

Losses may be added to or subtracted from the meter registration.

Meters are usually installed on the low-voltage side of a transformer because it is more cost-effective. There are also cases where change of ownership may occur halfway along a transmission line where it is impractical to install a meter. In this case, power metering must again be compensated.

## LINE LOSS AND TRANSFORMER LOSS AFTER THE PCC

The PCC (Point of Common Coupling) is the interchange point between the distribution grid and a particular customer. Unlike losses that occur within a transmission/distribution network, which cannot be allocated to a single customer and must be rolled into the per-unit cost of electricity, losses that occur after the PCC can be measured and allocated accordingly.

## CAUSES OF LINE LOSS

Line Losses are a result of passing current through an imperfect conductor such as copper. The conducting material has characteristic impedance that produce a voltage drop along the line proportional to the current flow. The total line impedance can be determined from the elements on the previous chart:

The resistive component (R) of the impedance (Z) contributes to active power losses (Ploss), while the reactive component (X) contributes to reactive power losses (Qloss).

The line-losses can be calculated based on the measured current load as:

$$LLW = P_{loss} = I \times \left(I \times \frac{r}{l} \times L\right) = I^2 \times R \qquad (1)$$

$$LLV = Q_{loss} = I \times \left(I \times \frac{x}{l} \times L\right) = I^2 \times X \qquad (2)$$

For a 3-phase system, the losses for each phase are calculated separately according to the measured current as:

$$P_{loss-tot} = (P_{loss-a} + P_{loss-b} + P_{loss-c}) = (I_a^2 \times R_a + I_b^2 \times R_b + I_c^2 \times R_c) \qquad (3)$$

$$Q_{loss-tot} = (Q_{loss-a} + Q_{loss-b} + Q_{loss-c}) = (I_a^2 \times X_a + I_b^2 \times X_b + I_c^2 \times X_c) \qquad (4)$$

If we assume that the per-phase impedance is similar and use the average impedance, the equation simplifies to:

$$LLW = P_{loss-avg} = \frac{(I_a^2 + I_b^2 + I_c^2)}{3} \times R = I^2_{avg} \times R \qquad (5)$$

$$LLV = Q_{loss-avg} = \frac{(I_a^2 + I_b^2 + I_c^2)}{3} \times X = I^2_{avg} \times X \qquad (6)$$

## CAUSES OF TRANSFORMER LOSS

Power transformer losses are a combination of the power dissipated by the core's magnetizing inductance (Iron loss) and the winding's impedance (Copper loss).

Iron losses are a function of the applied voltage and are often referred to as "noload losses" - they are induced even when there is no load current. Copper losses are a function of the winding current and are often referred to as "load losses".

These losses are calculated for any operating condition if a few parameters of the power transformer are known. The transformer manufacturer commonly provides this information on the transformer test sheet:

- rated total kVA of the power transformer (VATXtest).
- rated voltage of the power transformer (VTXtest).
- No-load test watts (LWFeTXtest) - the active power consumed by the transformer's core at the rated voltage with no load current (open circuit test).
- Full-load test watts (LWCuTXtest) - the active power consumed by the transformer's windings at full load current for rated kVA (short circuit test).
- %Excitation current - ratio of No-load test current (at rated voltage) to full load current.
- %Impedance - ratio of Full-load test voltage (at rated current) to rated voltage.

The No-Load and Full-Load VAR losses (LVFeTXtest and LVCuTXtest) may not be provided, but are calculated from the above data.

$$LVFe_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Excitation}{100}\right)^2 - (LWFe_{TXtest})^2} \tag{7}$$

$$LVCu_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Impedance}{100}\right)^2 - (LWCu_{TXtest})^2} \tag{8}$$

To determine the actual transformer losses, the test losses must be scaled for use at the actual operating voltage and current.

$$LWFe = LWFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^2 \tag{9}$$

$$LVFe = LVFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^4 \tag{11}$$

$$LWCu = LWCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \tag{10}$$

$$LVCu = LVCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \tag{12}$$

## LOSS COMPENSATION IN ION METERS

ION meters that support loss compensation in their default framework are the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters. For information about Loss Compensation in the ION7700 and ION7300 series, please contact Schneider Electric.

The meters have the following Transformer and Line Loss Compensation features:

- Compensation performed on 1-second total power (kW total, kVAR total, and kVA total).

| Power Transformer Wiring (metered side) | ION8300/ION8400/ ION8500 Volts Mode | ION7550, ION7650 Meters Volts Mode |
|---|---|---|
| 3-Wire Closed Delta | 35S | Delta |
| 4-Wire WYE (3 element) | 9S | 4-Wire WYE |
| 4-Wire WYE (2½ element)* | 36S | 3-Wire WYE |
| 3-Wire WYE | 9S | 3-Wire WYE |

**V2 values are only accurate for balanced loads**

- Unbalanced loads are handled accurately (except in the case of line-loss of neutral conductor in a 4-Wye system).
- Losses may be added or subtracted.
- Compensation works in all four power quadrants.
- Compensation is available in TEST mode. Support for compensation on singlephase test sets is also available in TEST mode.
- Compensation works correctly when all revenue parameters are reported in secondary units (meter units).

By default, the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters come configured to provide the following compensated registers:

For Total kW, Total kVAR, and Total kVA quantities:

- Real-time power
- Demand: Thermal and Block
- Calibration Pulsers
- Min/Max

For Total kWh, Total kVARh, and Total kVAh quantities:

- Energy
- Interval Energy
- Energy in Test Mode
- Energy for each TOU rate

The ION8300/ION8400/ION8500 and the ION7550 and ION7650 offer two possible loss calculation methods. One must be selected when Loss Compensation is enabled:

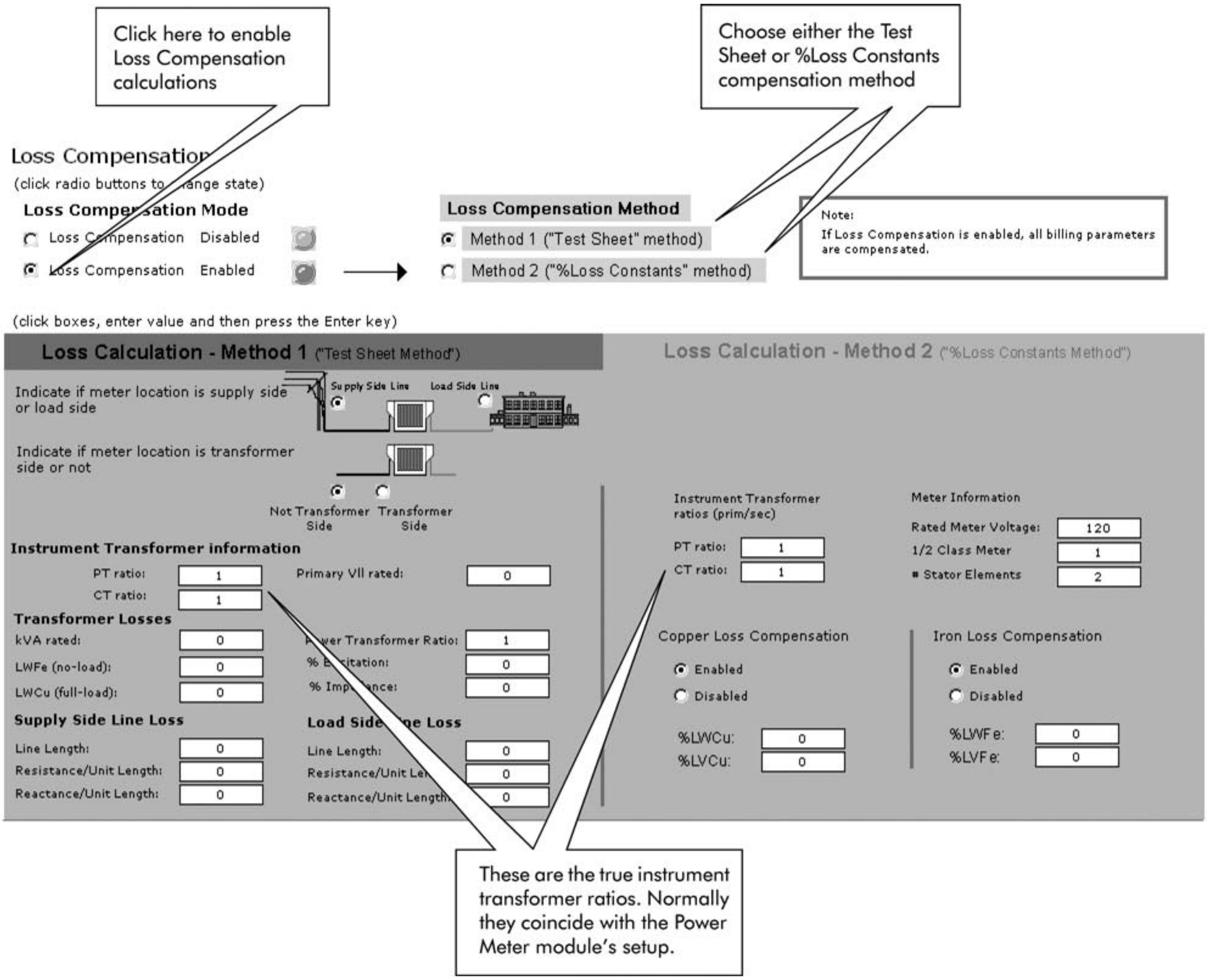
- Test Sheet (Method 1)
- %Loss Constants (Method 2)

Both methods are based on the same calculations and produce identical results if the correct input parameters are programmed into the meter. The difference between these methods is in the type of parameters required to perform the loss calculations.

To simplify verification in Method 2, the user is required to calculate the parameters in advance.

## CAUTION

Due to the variation in installations, advanced knowledge of power systems and connection methods is required before transformer loss compensation can be properly implemented. Data parameters should only be programmed by qualified personnel that have appropriate training and experience with Transformer Loss Compensation calculations.



Click here to enable Loss Compensation calculations

Choose either the Test Sheet or %Loss Constants compensation method

Loss Compensation

(click radio buttons to change state)

**Loss Compensation Mode**

○ Loss Compensation Disabled

● Loss Compensation Enabled

**Loss Compensation Method**

● Method 1 ("Test Sheet" method)

○ Method 2 ("%Loss Constants" method)

Note:
If Loss Compensation is enabled, all billing parameters are compensated.

(click boxes, enter value and then press the Enter key)

**Loss Calculation - Method 1** ("Test Sheet Method")

Indicate if meter location is supply side or load side: ● Supply Side Line ○ Load Side Line

Indicate if meter location is transformer side or not: ● Not Transformer Side ○ Transformer Side

**Instrument Transformer information**

PT ratio: 1

CT ratio: 1

Primary Vll rated: 0

**Transformer Losses**

kVA rated: 0

LWFe (no-load): 0

LWCu (full-load): 0

Power Transformer Ratio: 1

% Excitation: 0

% Impedance: 0

**Supply Side Line Loss**

Line Length: 0

Resistance/Unit Length: 0

Reactance/Unit Length: 0

**Load Side Line Loss**

Line Length: 0

Resistance/Unit Length: 0

Reactance/Unit Length: 0

**Loss Calculation - Method 2** ("%Loss Constants Method")

Instrument Transformer ratios (prim/sec)

PT ratio: 1

CT ratio: 1

Meter Information

Rated Meter Voltage: 120

1/2 Class Meter: 1

# Stator Elements: 2

Copper Loss Compensation

● Enabled

○ Disabled

%LWCu: 0

%LVCu: 0

Iron Loss Compensation

● Enabled

○ Disabled

%LWFe: 0

%LVFe: 0

These are the true instrument transformer ratios. Normally they coincide with the Power Meter module's setup.

## SUPPORTED TLC CONFIGURATIONS

When compensation is enabled, the meter calculates transformer and line loss based on a set of input parameters. These parameters determine whether the meter adds or subtracts the losses from the measured power. Compensation can be enabled using either the Vista component of ION Enterprise or ION Setup.

## CONFIGURING LOSS COMPENSATION USING VISTA

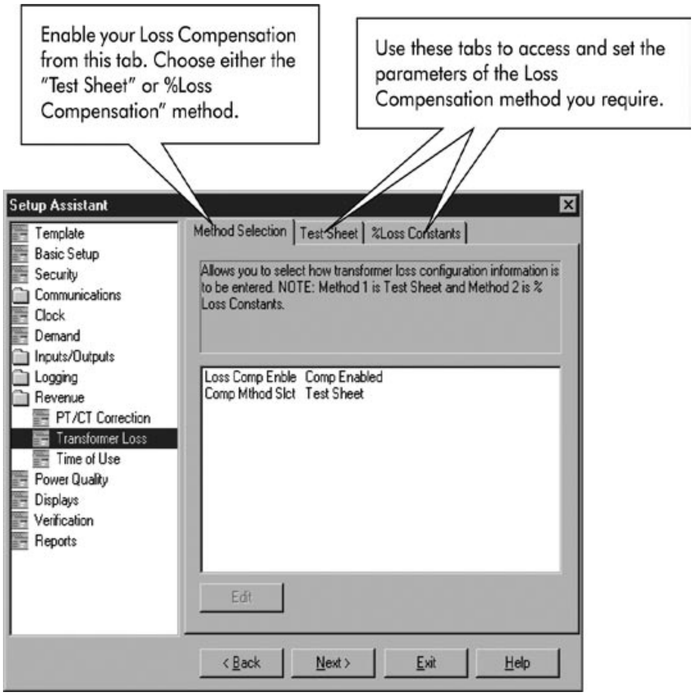
Click the Loss Compensation button in the Revenue screen to access the Loss
Compensation screen:

1. Launch Vista.
2. In the User Diagram screen that appears, click the Revenue button.
3. Click the Loss Compensation button. The following window appears (the screen for ION8300/ION8400/ION8500 Loss Compensation is shown below):
4. Configure your values as required.

For a detailed explanation of values and their calculations, see "Loss Compensation Input Parameters".

## CONFIGURING LOSS COMPENSATION USING ION SETUP

1. Log on to ION Setup and connect to the appropriate me-



Enable your Loss Compensation from this tab. Choose either the "Test Sheet" or %Loss Compensation" method.

Use these tabs to access and set the parameters of the Loss Compensation method you require.

Allows you to select how transformer loss configuration information is to be entered. NOTE: Method 1 is Test Sheet and Method 2 is % Loss Constants.

Loss Comp Enble Comp Enabled
Comp Mthod Slct Test Sheet

ter.

2. Double-click the Setup Assistant and navigate to the Revenue > Transformer
Loss screen.

3. Click the Method Selection tab to select how Transformer Loss information is entered.

4. Click either the %Loss Constant or the Test Sheet tabs (depending on your selected calculation method) and configure the value settings.

## SINGLE-PHASE TESTING IN ION SETUP

You can also test Transformer Line Loss with a single-phase source. To test with single-phase in ION Setup:

1. Log on to ION Setup and connect to the appropriate meter.

2. Double-click the Setup Assistant and select the Verification screen.

3. Select Test Mode and click Display.
A window appears informing you the meter is now in test mode.

4. Select Volts, Amps and Power.

5. Click Loss Mode and select Single Phase.

6. In the Setup Assistant screen, navigate to Revenue > Transformer Loss and set your loss parameters.

## LOSS COMPENSATION INPUT PARAMETERS

Depending on the method chosen for Transformer Loss Compensation, the meter requires specific data parameters to be programmed into the meter. The data for each method is listed below. All parameters can be programmed into the meter using ION software.

The following is a detailed description of the input parameters required by both methods.

## INPUT PARAMETERS FOR METHOD 1: "TEST SHEET"

Line losses and transformer losses are calculated separately and applied to the measured power, energy and demand quantities based on the location of the meter with regards to the power transformer, supply-side line and load-side line.

All parameters required for this method can be obtained from the transformer and line manufacturer.

The same unit of length (meter or foot) must be used for all parameters.

### LINE LOSS CALCULATION PARAMETERS:

$$\text{Power Transformer Ratio} = \left(\frac{\text{Voltage on supply side}}{\text{Voltage on load side}}\right)$$

The value of Power Transformer Ratio will be less than 1 for generation applications. If there is no power transformer used, set this value to 1.

For the line on the supply side (SY) of the transformer:

$$\text{Resistance/Unit length } \left(\frac{r}{l_{sy}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Reactance/Unit length } \left(\frac{x}{l_{sy}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Line length}_{sy} \text{ in } [\text{m}] \text{ or } [\text{ft}]$$

For the line on the load side (LD) of the transformer:

$$\text{Resistance/Unit length } \left(\frac{r}{l_{ld}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Reactance/Unit length } \left(\frac{x}{l_{ld}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Line length}_{ld} \text{ in } [\text{m}] \text{ or } [\text{ft}]$$

ION meters then calculate the line losses as:

$$\text{LLW[W]} = I^2_{avg} \times \frac{r}{l} \times \text{Line Length} \times 3 \qquad (13a)$$

$$\text{LLV[VAR]} = I^2_{avg} \times \frac{x}{l} \times \text{Line Length} \times 3 \qquad (13b)$$

These calculations are performed separately for the supply side part of the line and the load side part.

## TRANSFORMER LOSS CALCULATION PARAMETERS:

When this method is selected, then the following power transformer and line data is programmed into the meter:

- Rated power transformer voltage (VLL on metered-side of Power Transformer)
- Rated power transformer kVA
- Power transformer ratio (Voltage on Supply Side/Voltage on Load Side)
- No-load iron test loss watts
- Full-load copper test loss watts
- Percent exciting current
- Percent impedance
- Line length of load-side and supply-side line
- Resistance and reactance per unit length for both lines
- Instrument transformer ratios (VTR, CTR)
- Information about the location of the meter with regards to the power transformer, supply-side line and load-side line

The iron and copper losses are then calculated using equations 7 to 12, based on the measured load current and voltage.

## LINE LOSS AND TRANSFORMER LOSS COMPENSATION

Once the losses are calculated, you can add or subtract losses from the measured active and reactive power values in real-time.

### METERING LOCATION PARAMETERS:

- MP Definition 1

This parameter indicates if the power monitor (metering point) is installed on the supply side of the transformer or the load side.

- MP Definition 2

This parameter indicates if the power monitor (metering point) is installed on the transformer end of the line or on the far end.

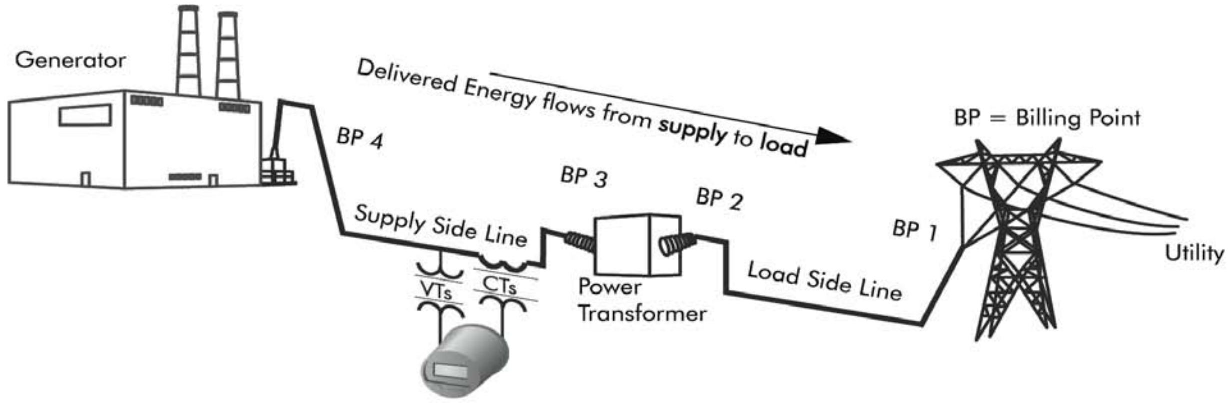
## USE CASES: METERING POINT & BILLING POINT

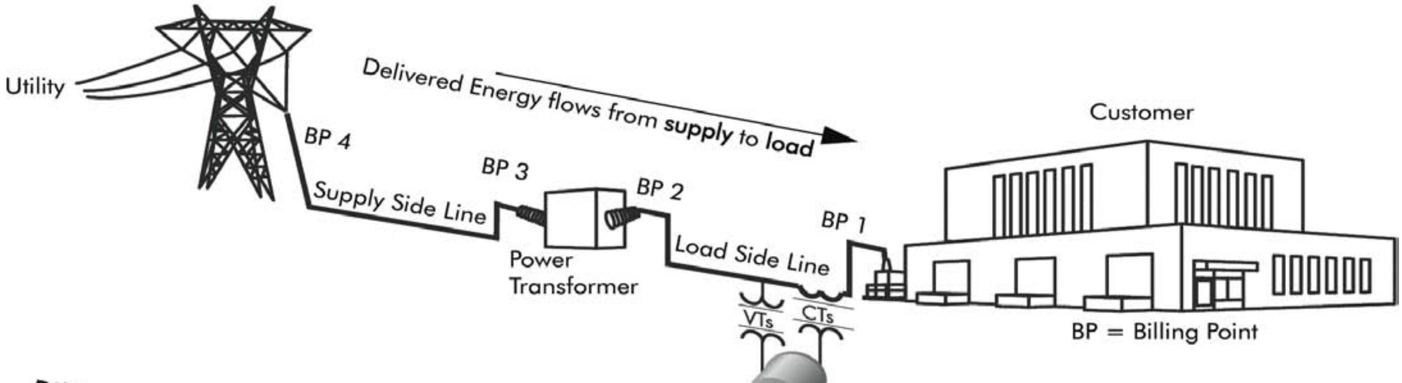
## LOCATIONS

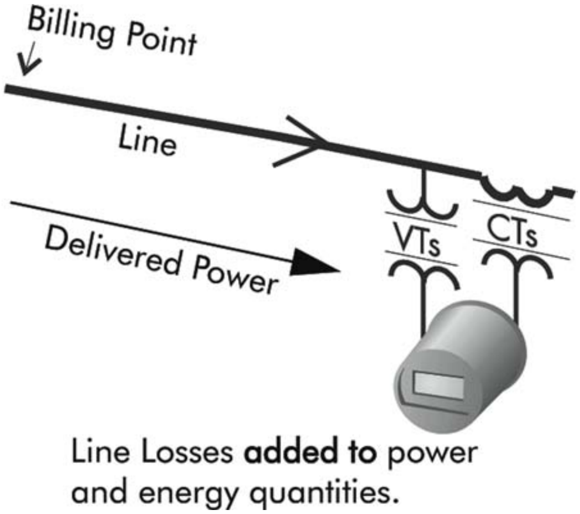
The following diagram outlines the possible locations of the billing points (BP) and metering points.

Some scenarios involve energy delivered from generator to the Utility, and others from the Utility to the customer.

The following examples show how the location of the power monitor and the billing point affect the calculation of compensated power values.







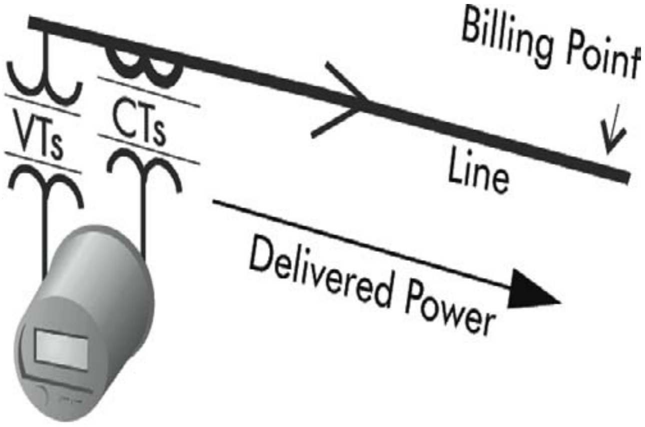
| Parameter | | Setting |
|---|---|---|
| MP Definition 1 | = | Load Side |
| MP Definition 2 | = | Not Transformer Side |
| PT ratio | = | enter Instrument Transformer data |
| CT ratio | = | enter Instrument Transformer data |
| $r/l_{ld}$ | = | enter resistance in [Ω/m] or [Ω/ft] |
| $x/l_{ld}$ | = | enter reactance in [Ω/m] or [Ω/ft] |
| Line length$_{ld}$ | = | enter line length in [m] or [ft] |

## LINE LOSS ONLY

### ADDING LINE LOSSES:

Line losses are added to the delivered power and energy quantities. Set the loss calculation parameters in the meter as above:

Leave all other parameters at their default settings.



Line Losses **subtracted from** power and energy quantities.

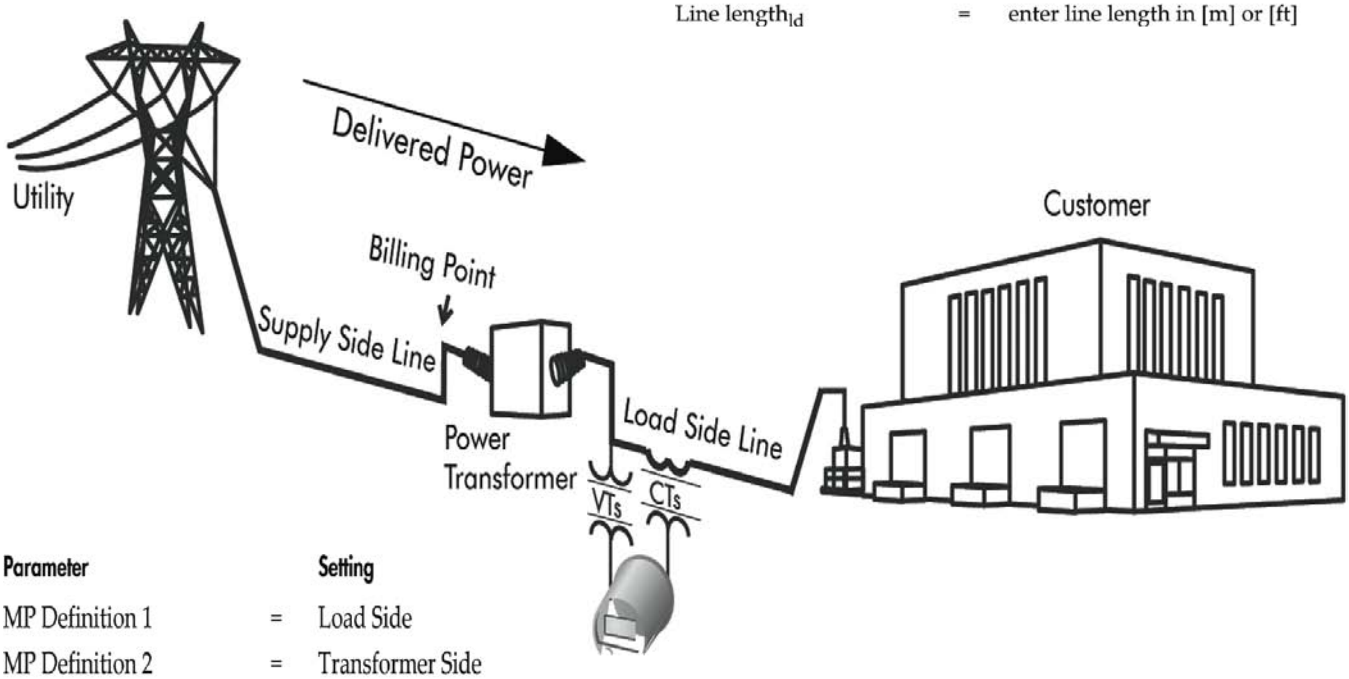
### SUBTRACTING LINE LOSSES:

Change MP Definition 2 to "Transformer Side" so that the line losses are subtracted from the power and energy quantities.

### TRANSFORMER LOSS ONLY
### ADDING TRANSFORMER LOSSES:

Transformer losses are added to power and energy quantities. The loss calculation parameters in the meter should be set as follows:

| **Parameter** | | **Setting** |
|---|---|---|
| MP Definition 1 | = | Load Side |
| MP Definition 2 | = | Not Transformer Side |
| PT ratio | = | enter Instrument Transformer data |
| CT ratio | = | enter Instrument Transformer data |
| $r/l_{ld}$ | = | enter resistance in [Ω/m] or [Ω/ft] |
| $x/l_{ld}$ | = | enter reactance in [Ω/m] or [Ω/ft] |
| Line length$_{ld}$ | = | enter line length in [m] or [ft] |

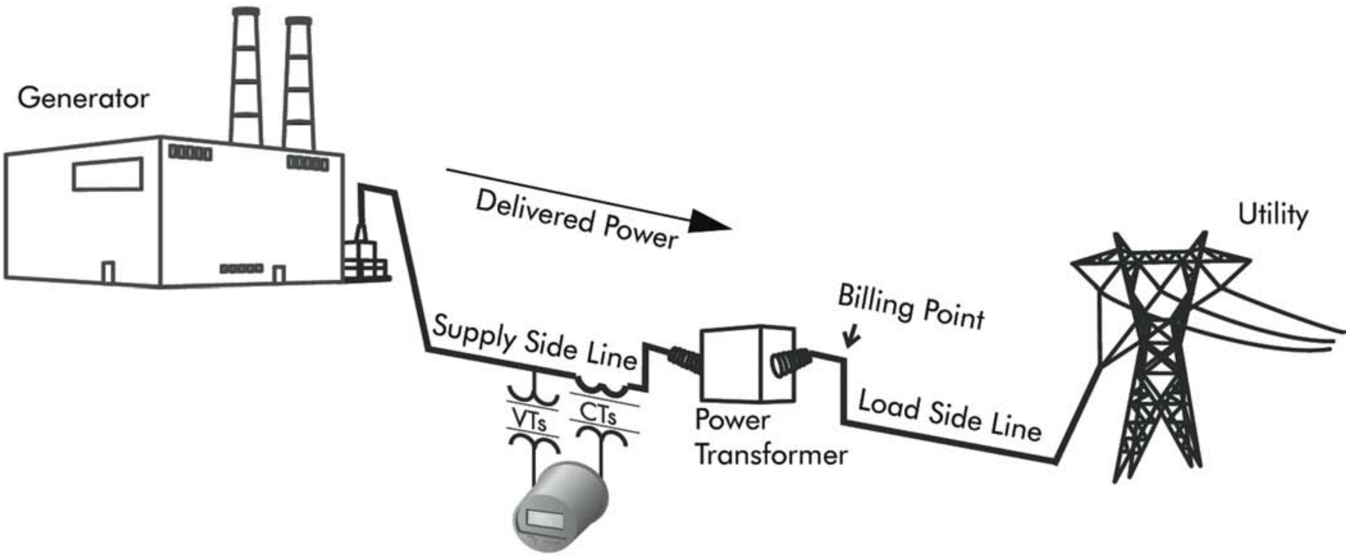


| **Parameter** | | **Setting** |
|---|---|---|
| MP Definition 1 | = | Load Side |
| MP Definition 2 | = | Transformer Side |
| PT ratio | = | enter Instrument Transformer data |
| CT ratio | = | enter Instrument Transformer data |
| $Vll_{rated}$ | = | enter Transformer data |
| $LWFe_{test}$ | = | enter Transformer data |
| $LWCu_{test}$ | = | enter Transformer data |
| %Excitation | = | enter Transformer data |
| %Impedance | = | enter Transformer data |

Leave all other parameters at their default settings.

### SUBTRACTING TRANSFORMER LOSSES:

Change MP Definition 1 to "Supply Side" so that transformer losses are subtracted from the power and energy quantities.



## LINE LOSS AND TRANSFORMER LOSS

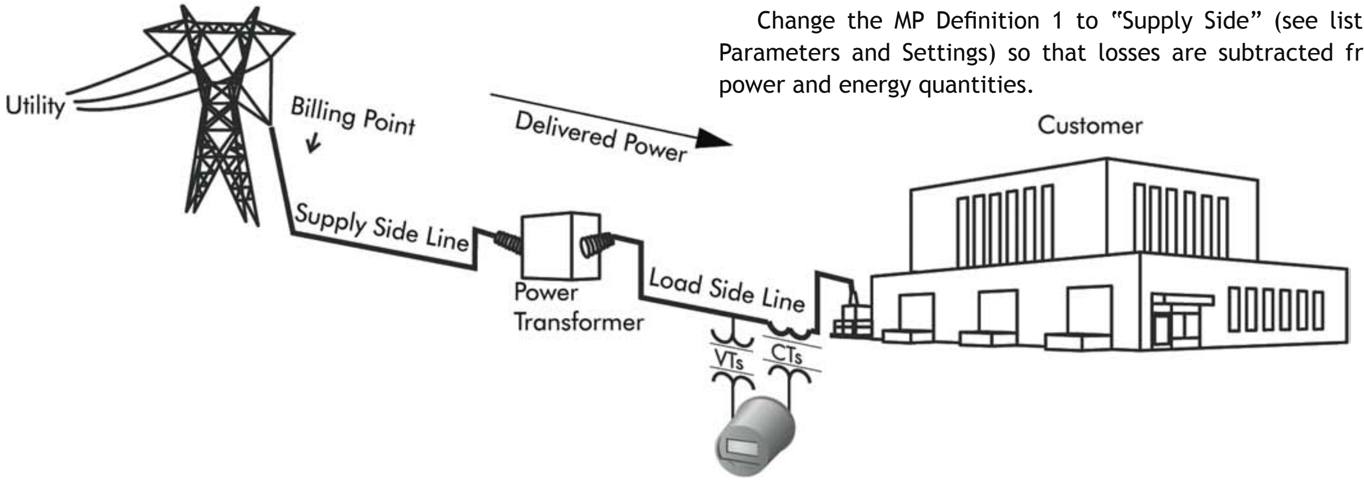
### ADDING LINE & TRANSFORMER LOSSES:

The transformer and line losses are added to measured power and energy values. Set the meter's loss calculation parameters to:

Leave all other parameters at their default settings. To ignore load-side or supply-side line losses, set the corresponding length to zero.

### SUBTRACTING LINE & TRANSFORMER LOSSES:

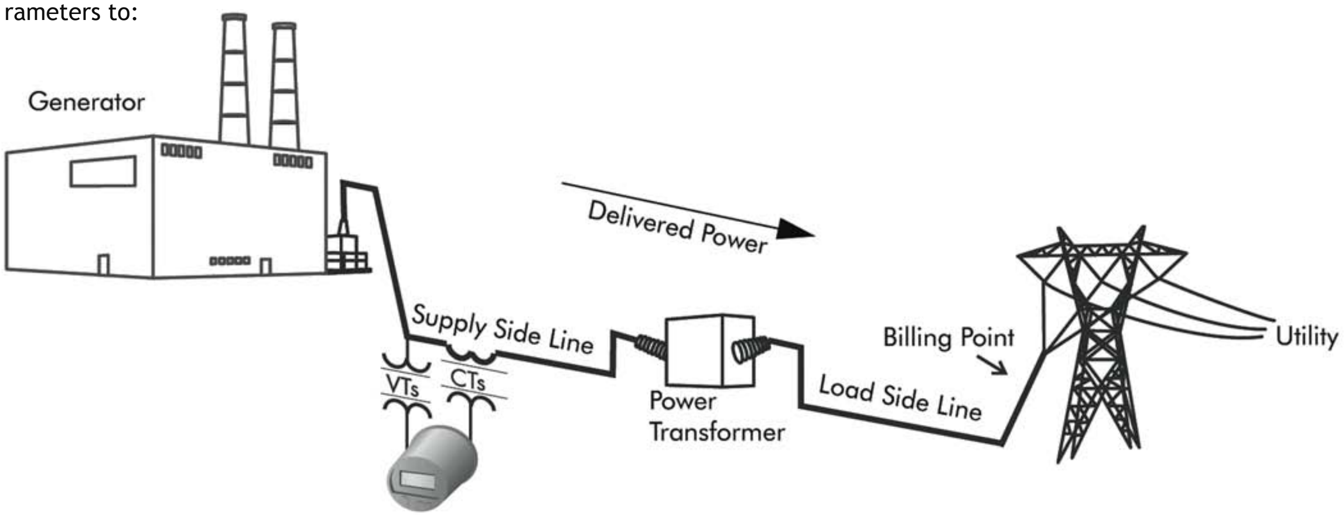
Change the MP Definition 1 to "Supply Side" (see list of Parameters and Settings) so that losses are subtracted from power and energy quantities.



### ADDING LINE & TRANSFORMER LOSSES:

The transformer and line losses are added to measured power and energy values. Set the meter's loss calculation parameters to:

Leave all other parameters at their default settings. To ignore load-side or supply-side line losses, set the corresponding length to zero.



| Parameter | | Setting |
|---|---|---|
| MP Definition 1 | = | Load Side |
| MP Definition 2 | = | Not Transformer Side |
| PT ratio | = | enter Instrument Transformer data |
| CT ratio | = | enter Instrument Transformer data |
| Power Transformer Ratio | = | (Voltage on Supply Side/Voltage on Load Side) |
| $\mathrm{Vll}_{\mathrm{rated}}$ | = | enter Transformer data |
| $\mathrm{LWFe}_{\mathrm{test}}$ | = | enter Transformer data |
| $\mathrm{LWCu}_{\mathrm{test}}$ | = | enter Transformer data |
| %Excitation | = | enter Transformer data |
| %Impedance | = | enter Transformer data |
| $r/l_{sy}$ | = | enter resistance in [Ω/m] or [Ω/ft] |
| $x/l_{sy}$ | = | enter reactance in [Ω/m] or [Ω/ft] |
| Line $\mathrm{length}_{sy}$ | = | enter line length in [m] or [ft] |
| $r/l_{LD}$ | = | enter resistance in [Ω/m] or [Ω/ft] |
| $x/l_{LD}$ | = | enter reactance in [Ω/m] or [Ω/ft] |
| Line $\mathrm{length}_{ld}$ | = | enter line length in [m] or [ft] |

## SUBTRACTING LINE & TRANSFORMER LOSSES:

Change the MP Definition 1 to "Supply Side" (see list of Parameters and Settings) so that losses are subtracted from power and energy quantities.

## INPUT PARAMETERS FOR METHOD 2: "% LOSS CONSTANTS"

When using this method in ION meters with a delta connection, compute the %Loss values with respect to the single-phase system kVA. To confirm TLC operation, verify that the amount of compensated watts matches the expected.

In this method, line loss and transformer loss calculation parameters are computed manually or through a third party program into four (4) loss constants. These values are then programmed into the meter. The meter uses these constants to calculate the losses and perform the compensation.

This method allows you to enable or disable iron and copper loss calculations separately. When this method is selected, the following data must be programmed into the meter:

- Percent iron Watt loss constant (%LWFe)*
- Percent copper Watt loss constant (%LWCu)*
- Percent iron VAR loss constant (%LVFe)*
- Percent copper VAR loss constant (%LVCu)*
- Instrument transformer ratios (VTR, CTR)
- Rated meter voltage (VMrated)
- 1/2 Class meter current (1/2IMrated)
- Number of stator elements (2 for Delta connections, 3 for WYE)

* If you want the losses to be subtracted from Delivered Energy, enter negative values for the percent loss constants.

The field "# stator elements" indicate the number of metering elements to configure for transformer loss compensation:

| ION8300/<br>ION8400/<br>ION8500 Volts Mode | ION7550, ION7650 Meters<br>Volts Mode | Number of stator elements |
|---|---|---|
| 35S | Delta | 2 |
| 9S, 36S | 4-Wire WYE<br>3-Wire WYE | 3 |

These are the values you program into the ION meter. To properly implement Transformer Loss Calculations using Method 2, you must calculate constants using the following relationships. See "Appendix A: Glossary" and ensure you fully understand the terms used below. Failure to calculate exactly as outlined below will result in incorrect readings.

## PERCENT-LOSS CONSTANT CALCULATIONS

Both L-L, or both L-N

$$\%\mathrm{LWFe} = \frac{\mathrm{LWFe}_{\mathrm{TXtest}} \times \left[\frac{V_{\mathrm{Mrated}} \times \mathrm{VTR}}{V_{\mathrm{TXtest}}}\right]^2}{\text{½ Class System VA}} \times 100\% \qquad (14)$$

Both L-L, or both L-N

$$\%\mathrm{LVFe} = \frac{\mathrm{LVFe}_{\mathrm{TXtest}} \times \left[\frac{V_{\mathrm{Mrated}} \times \mathrm{VTR}}{V_{\mathrm{TXtest}}}\right]^4}{\text{½ Class System VA}} \times 100\% \qquad (15)$$

$$\%\mathrm{LWCu} = \frac{\mathrm{LWCu}_{\mathrm{TXtest}} \times \left[\frac{\tfrac{1}{2}I_{\mathrm{Mclass}} \times \mathrm{CTR}}{I_{\mathrm{TXtest}}}\right]^2 + \mathrm{LLW}_{\mathrm{Mclass}}}{\text{½ Class System VA}} \times 100\% \qquad (16)$$

$$= \frac{(\tfrac{1}{2}I_{\mathrm{Mclass}} \times \mathrm{CTR})^2 \times \text{Total System Resistance}}{\text{½ Class System VA}} \times 100\%$$

System Resistance and System Reactance include both transformer and line impedance.

$$\%LVCu = \frac{LVCu_{TXtest} \times \left[\frac{½I_{Mclass} \times CTR}{I_{TXtest}}\right]^2 + LLW_{Mclass}}{½ \text{ Class System VA}} \times 100\%$$
$$= \frac{(½I_{Mclass} \times CTR)^2 \times \text{Total System Reactance}}{½ \text{ Class System VA}} \times 100\% \tag{17}$$

## LOSS CALCULATIONS IN ION METERS

ION meters use these constants to calculate the losses as follows:

$$LWFe = \frac{\%LWFe}{100} \times ½ \text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^2 \tag{19}$$

$$LVFe = \frac{\%LVFe}{100} \times ½ \text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^4 \tag{20}$$

$$LWCu = \frac{\%LWCu}{100} \times ½ \text{ Class System VA} \times \left[\frac{I_{actual}}{½I_{Mclass}}\right]^2 \tag{21}$$

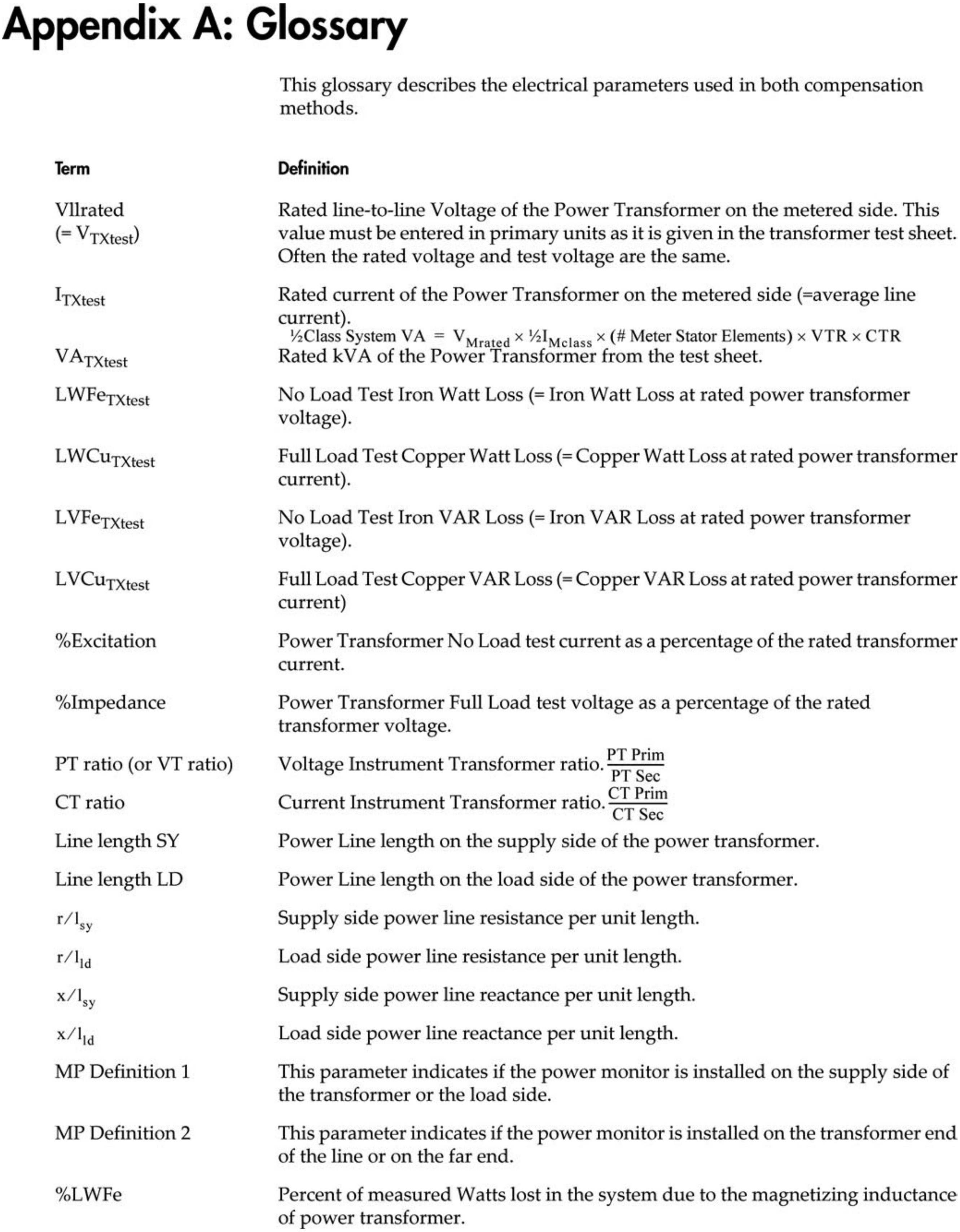
$$LVCu = \frac{\%LVCu}{100} \times ½ \text{ Class System VA} \times \left[\frac{I_{actual}}{½I_{Mclass}}\right]^2 \tag{22}$$

**Important Note for Percent-Loss Loss Equations (14-17) and Power Loss Equations (19 - 22)**

Because the meter's first step in its "Loss Calculations" computation is to cancel out the "1/2 Class System VA" value, the "1/2 Class System VA" value that is used in the "Percent-Loss Constant Calculations" must be calculated exactly as outlined in equation 18 (above). If the "1/2 Class System VA" value is not what the meter expects, the two terms will not fully cancel out. This will result in incorrect loss calculations.

## Appendix A: Glossary

This glossary describes the electrical parameters used in both compensation methods.

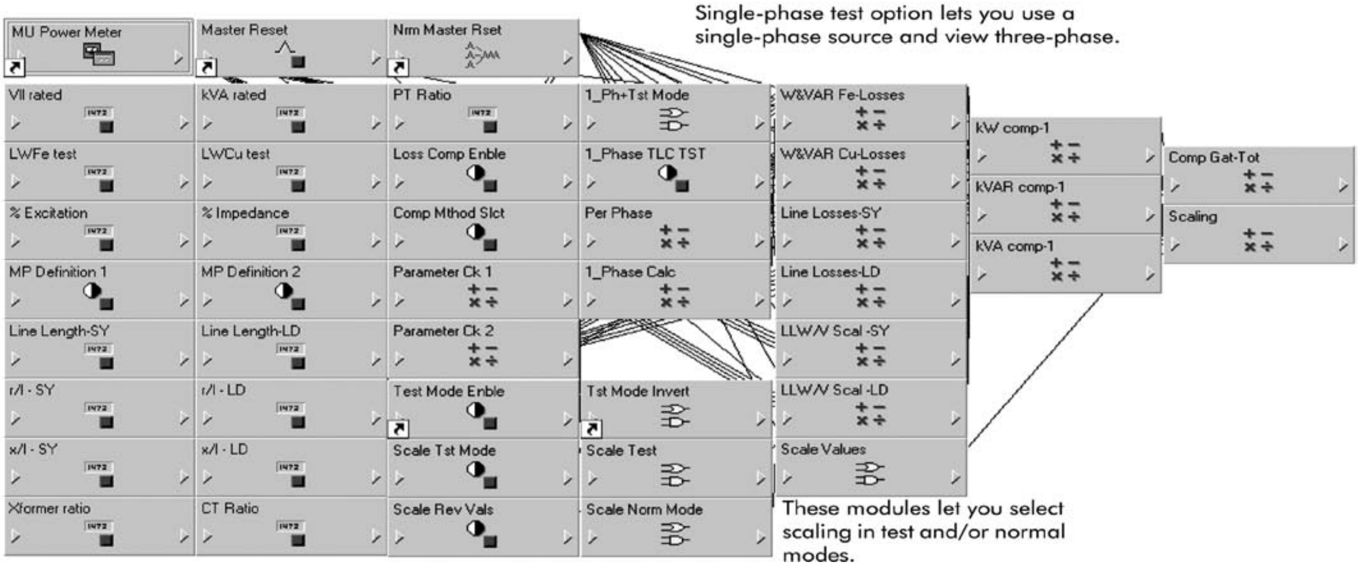


# Appendix A: Glossary

This glossary describes the electrical parameters used in both compensation methods.

| Term | Definition |
|---|---|
| Vllrated<br>(= $V_{TXtest}$) | Rated line-to-line Voltage of the Power Transformer on the metered side. This value must be entered in primary units as it is given in the transformer test sheet. Often the rated voltage and test voltage are the same. |
| $I_{TXtest}$ | Rated current of the Power Transformer on the metered side (=average line current).<br>$½\text{Class System VA} = V_{Mrated} \times ½I_{Mclass} \times (\text{\# Meter Stator Elements}) \times VTR \times CTR$ |
| $VA_{TXtest}$ | Rated kVA of the Power Transformer from the test sheet. |
| $LWFe_{TXtest}$ | No Load Test Iron Watt Loss (= Iron Watt Loss at rated power transformer voltage). |
| $LWCu_{TXtest}$ | Full Load Test Copper Watt Loss (= Copper Watt Loss at rated power transformer current). |
| $LVFe_{TXtest}$ | No Load Test Iron VAR Loss (= Iron VAR Loss at rated power transformer voltage). |
| $LVCu_{TXtest}$ | Full Load Test Copper VAR Loss (= Copper VAR Loss at rated power transformer current) |
| %Excitation | Power Transformer No Load test current as a percentage of the rated transformer current. |
| %Impedance | Power Transformer Full Load test voltage as a percentage of the rated transformer voltage. |
| PT ratio (or VT ratio) | Voltage Instrument Transformer ratio. $\frac{\text{PT Prim}}{\text{PT Sec}}$ |
| CT ratio | Current Instrument Transformer ratio. $\frac{\text{CT Prim}}{\text{CT Sec}}$ |
| Line length SY | Power Line length on the supply side of the power transformer. |
| Line length LD | Power Line length on the load side of the power transformer. |
| $r/l_{sy}$ | Supply side power line resistance per unit length. |
| $r/l_{ld}$ | Load side power line resistance per unit length. |
| $x/l_{sy}$ | Supply side power line reactance per unit length. |
| $x/l_{ld}$ | Load side power line reactance per unit length. |
| MP Definition 1 | This parameter indicates if the power monitor is installed on the supply side of the transformer or the load side. |
| MP Definition 2 | This parameter indicates if the power monitor is installed on the transformer end of the line or on the far end. |
| %LWFe | Percent of measured Watts lost in the system due to the magnetizing inductance of power transformer. |

| | |
|---|---|
| %LWCu | Percent of measured Watts lost in the system due to impedance in lines and windings. |
| %LVFe | Percent of measured VARs lost in the system due to the magnetizing inductance of power transformer. |
| %LVCu | Percent of measured VARs lost in the system due to impedance in lines and windings. |
| System Resistance | Sum of power transformer and line resistance on all phases. |
| System Reactance | Sum of power transformer and line reactance on all phases. |
| $V_{Mrated}$ (Rated Meter Voltage) | Nominal meter input voltage. This is the value used in the calculation of the Percent Iron Loss constants. The rated meter voltage will be a line-to-neutral voltage for 3 element metering and a line-to-line voltage for 2 element metering. The Rated Meter Voltage must be entered in meter units (= unscaled). |
| $½I_{Mrated}$ (½ Class Meter Current) | Half the value of the certified meter class current. This value has to match the value used in the calculation of the Percent Loss Constants. |
| # of Stator Elements | Number of measuring elements used in the meter. This number is determined by the form factor of the power monitor. 9S meters for example in a 4 wire application use 3 elements. 35S meters used for 3 wire applications use 2 elements. |
| $LLV_{Mclass}$ | Line loss VARs at the meter's ½ class current. |
| $LLW_{Mclass}$ | Line Loss Watts at the meter's ½ class current. |



Single-phase test option lets you use a single-phase source and view three-phase.

These modules let you select scaling in test and/or normal modes.

A division by "0" or a negative number in a square root would cause a "Not available" output on the Arithmetic modules.

Line loss totals must be scaled prior to final energy scaling since the line losses are I2R (measured in Watts). Note that there is no voltage component in this Watts measurement. Scaling line loss prior to final power scaling provides CT2 as a multiplier for line losses:

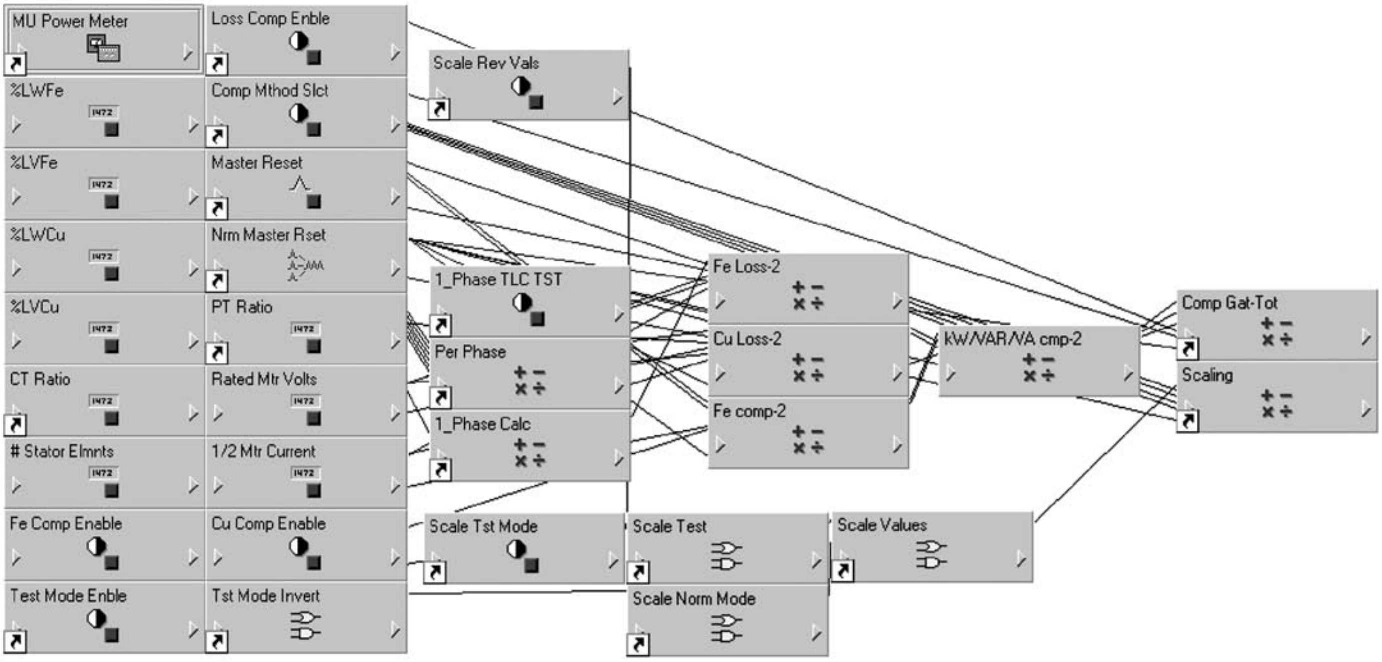
$$\text{Line Loss} = [\text{Losses in MU}] \times [\text{PTR} \times \text{CTR}]$$

$$= \left[\frac{(I_{\text{sec}} \times \text{CTR})^2 \times R}{\text{PTR} \times \text{CTR}}\right] \times (\text{PTR} \times \text{CTR})$$

$$= \left[(I_{\text{sec}})^2 \times R \times \frac{\text{CTR}}{\text{PTR}}\right] \times (\text{PTR} \times \text{CTR})$$

## METHOD 2: "%LOSS CONSTANTS"

The following screen capture shows the view of the framework in Designer:



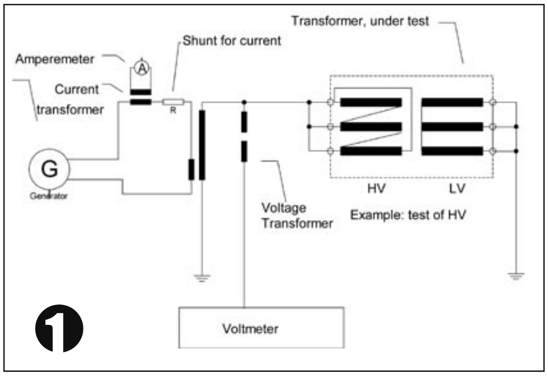
On the left side are the External Numeric and External Boolean modules that are used to enter transformer and line data for the loss calculations. The Arithmetic modules perform the actual calculations.

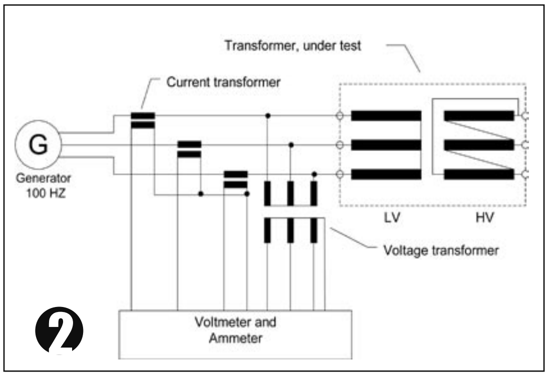
## SINGLE-PHASE TESTING

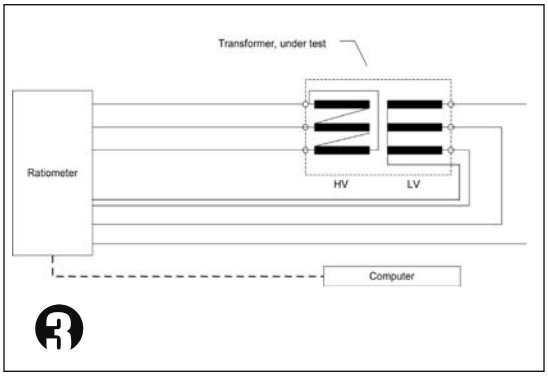
You can connect a single-phase source voltage in parallel and the current in series to simulate a three-phase source. Some ION meters automatically adjust the voltage in this test situation when the meter is in Test Mode and the single-phase option is selected.

# Guide For Testing Power Transformers

## Courtesy of Tesar







### INTRODUCTION

The following routine tests must be carried out on all power transformers:

- separate-source voltage withstand test
- induced voltage test
- voltage ratio measurement and check of polarities and connections
- no-load current and no-load loss measurement
- winding resistance measurement
- short-circuit impedance and load loss measurement
- partial discharge measurement in accordance with the International Basic Standards IEC 60726 for Dry-type power transformers

### 1 DIELECTRIC TESTS – SEPARATE-SOURCE VOLTAGE WITHSTAND TEST

The single-phase applied voltage wave shape shall be approximately sinusoidal. The test must be performed at rated frequency. At the end of the test, the test voltage shall be rapidly reduced up to 1/3 the full voltage before disconnection. The full test voltage shall be applied for 60 seconds between the winding under test and all the remaining windings, magnetic core, frame and enclosure connected to earth. The test shall be performed on all the windings. The test is successful if no failure occurs at full test voltage.

### 2 INDUCED VOLTAGE TEST

The test voltage shall be twice the value corresponding to the rated voltage; it shall be applied between the terminals of the secondary windings, by maintaining the primary winding open. The duration of the test at full voltage shall be 60 s, and the frequency twice the rated value. The test shall start with a voltage lower than 1/3 the full test voltage, and it shall be quickly increased up to full value. At the end of the test, the voltage shall be rapidly reduced up to 1/3 the rated value before disconnection. The test is successful if no failure occurs at full test voltage.

### 3 VOLTAGE RATIO MEASUREMENT AND CHECK OF POLARITIES AND CONNECTIONS

Voltage ratio measurement and check of polarities and connections shall be performed on all tapchanger positions; the correspondence between the numbers assigned to the tappings and the ratings shall also be checked. Voltage ratio measurement shall be performed phase by phase between the terminals of corresponding windings. Voltage ratio measurement is carried out by use of potentiometric method.

### 4 NO-LOAD CURRENT AND NO-LOAD LOSS MEASUREMENT

This test is performed by supplying LV windings at rated frequency and rated voltage. The wave shape shall be as nearly as possible of the sine-wave and the primary windings shall be open.

The frequency of the test shall not differ from the rated value more than ± 1%. No-load current and loss shall be measured as well as the mean value and the effective value of the voltage. If these two readings are equal, no correction shall be applied on the measurement of no-load loss; otherwise, no-load loss shall be referred to sine-wave condition in accordance with IEC Standards 60076-1. No-load current shall result as the average value of three readings performed by effective value ammeters. Three wattmeters shall be used to measure the power, by using instrument transformers and transducers when necessary.

### 5 WINDING RESISTANCE MEASUREMENT

Winding resistance measurement shall be performed when the windings are at ambient temperature without supply for a time long enough to achieve this condition. The measurements shall be carried out in direct current between terminals according to the sequence U-V; V-W; WU.

Ambient temperature shall also be measured. It shall result as the average value of three measurements performed by apposite thermal sensors.

## HV WINDING RESISTANCE MEASUREMENT

HV winding resistance measurement shall be performed by measuring simultaneously voltage and current. The voltmeter and ammeter must be connected as follows :

- voltmeter terminals must be connected beyond current cables;
- the current shall not exceed 10% of winding rated current;
- the measurement shall be carried out after voltage and current are stable.

Unless otherwise agreed, the HV winding shall be connected on principal tapping.

## LV WINDING RESISTANCE MEASUREMENT

LV winding resistance measurement shall be performed by measuring simultaneously voltage and current. The voltmeter and ammeter shall be connected as follows :

- voltmeter terminals shall be connected beyond current cables;
- the current shall not exceed 5% of winding rated current;
- the measurement shall be carried out after voltage and current are stable.

## 6 SHORT-CIRCUIT IMPEDANCE AND LOAD LOSS MEASUREMENT

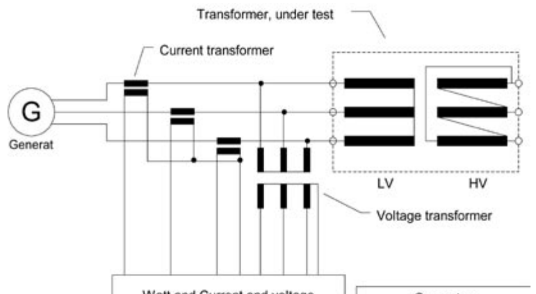
Short-circuit impedance and load loss measurement shall be performed at rated frequency, by applying on the transformer primary windings (connected on principal tapping) a three -phase sine-wave voltage system.

The secondary windings shall be short-circuited. Applied voltage, current and load loss shall be measured.

The frequency of the test shall not differ from the rated frequency more than ± 1%. In case the rated power is higher than 1000 kVA, load loss shall be measured by using three wattmeters, in order to reduce measurement uncertainties. When necessary, instrument transformers and transducers shall be used. The measured values shall be referred to rated current and then calculated at reference temperature. This temperature is the annual average ambient temperature (20°C) increased by the permissible temperature rise in accordance with the temperature class of the windings. IEC 60726 specify the permissible temperature rises on table no. 4. Beside, IEC 60076-1 give a complete explanation of how to perform the carries at rated current and at reference temperature.

## 7 PARTIAL DISCHARGE MEASUREMENT-A BASIC MEASURING CIRCUIT FOR PARTIAL DISCHARGE TEST IS SHOWN IN FIGURE 2 , IEC STANDARDS 60726.

The low-voltage windings shall be supplied from an alternate 100 Hz voltage source. The voltage shape shall be as nearly as possible of the sine-wave. Unless otherwise specified, a pre-stress voltage of 1,5 Um shall be induced for 30 s, followed without interruption by a voltage of 1,1 Um for three minutes, during which the partial discharge level shall be measured. The calibration of the measuring circuit is carried out by injecting simulated discharge pulses of 100pC at transformer terminals. Partial discharge measurement shall be carried out by use of an oscilloscope, in order to analyze the developing of the ongoing phenomena. Test procedures must be in accordance with IEC Standards 60726. The test is successful if the partial discharge level is lower than 20 pC unless otherwise agreed between manufacturer and purchaser.



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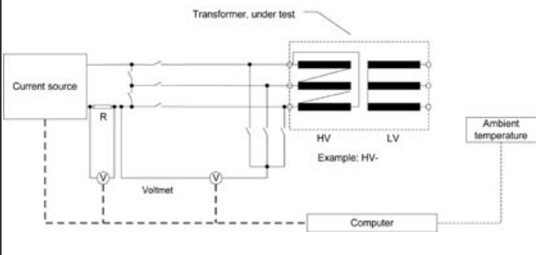

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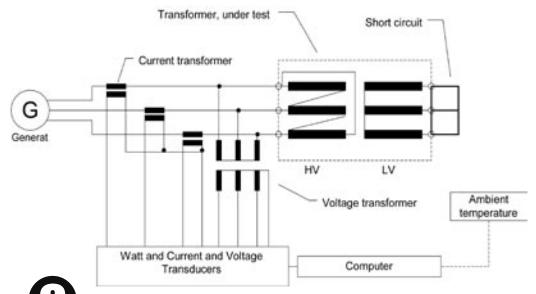

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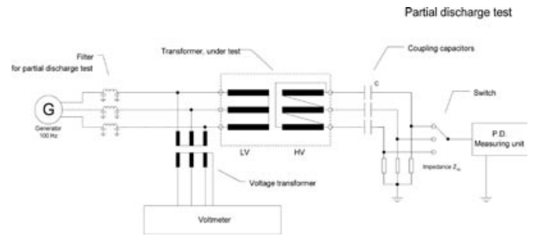


7

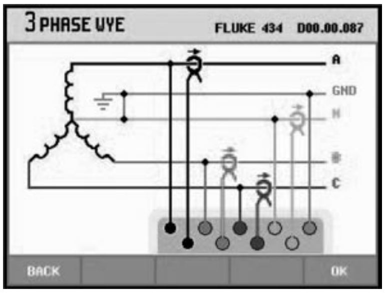
# Overheated Transformer

## Fluke

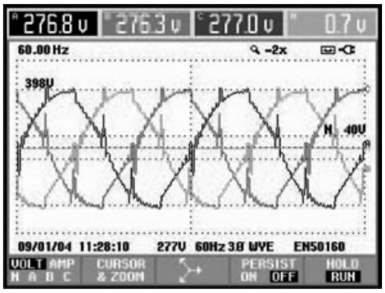
You could almost call it a happy accident. During a routine job at a large industrial facility, an electrical maintenance worker set a plastic kit on top of a nearby transformer. By the time he reached back for it a few minutes later, it had started to melt! Obviously, the transformer was operating well over its normal temperature range. The technician took a few readings with his DMM, but the numerical rms readout didn't reveal the problem. Suspecting the transformer was overloaded, he went to the equipment cage and brought back the team's three-phase power quality analyzer to calculate the apparent power (kVA) and see what the scope tool revealed.

### MEASUREMENTS

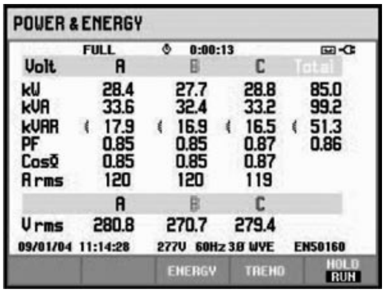
To verify the accuracy of his connections, the technician checked the View Config screen on the power quality analyzer. The one-line diagram matched up.



As a starting point, the technician pushed the Scope button, to check for distortion. The waveform signatures were in fact suspiciously distorted.



Next, he selected Power & Energy from the menu and compared the kVA calculated by the analyzer to the transformer nameplate's kVA. Sure enough, this transformer was heavily loaded (> 50%). That meant harmonics were also a concern.



POWER & ENERGY

FULL 0:00:13

| Volt | A | B | C | Total |
|---|---|---|---|---|
| kW | 28.4 | 27.7 | 28.8 | 85.0 |
| kVA | 33.6 | 32.4 | 33.2 | 99.2 |
| kVAR | ⟨ 17.9 | ⟨ 16.9 | ⟨ 16.5 | ⟨ 51.3 |
| PF | 0.85 | 0.85 | 0.87 | 0.86 |
| CosΦ | 0.85 | 0.85 | 0.87 | |
| A rms | 120 | 120 | 119 | |

| | A | B | C |
|---|---|---|---|
| V rms | 280.8 | 270.7 | 279.4 |

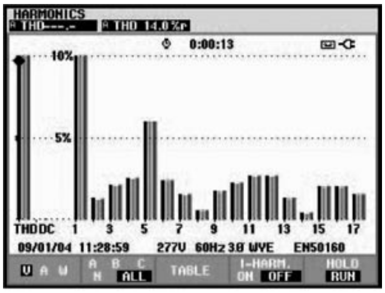
09/01/04 11:14:28 277V 60Hz 3Ø WYE EN50160

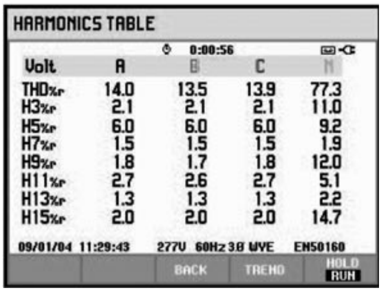
### POWER

Harmonics originate from loads that generate non-linear currents, such as adjustable speed drives, DC-powered equipment and even computers and office equipment. When these harmonic currents travel through the system impedance, they distort voltage sinewaves.

The voltage distortion then spreads the harmonic pollution throughout the system.

The technician selected the Harmonics function from the power quality analyzer menu and reviewed the Total Harmonic Distortion (THD) bar graph. THD measures the combined action of all the harmonics (on multiple frequencies) present, compared to the overall system. THD should not exceed 5%.





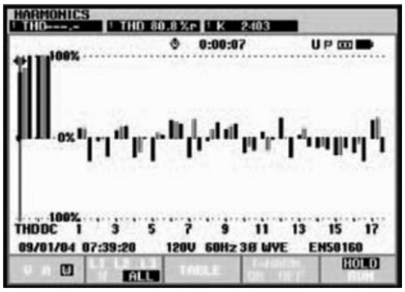
HARMONICS TABLE

0:00:56

| Volt | A | B | C | N |
|---|---|---|---|---|
| THD%r | 14.0 | 13.5 | 13.9 | 77.3 |
| H3%r | 2.1 | 2.1 | 2.1 | 11.0 |
| H5%r | 6.0 | 6.0 | 6.0 | 9.2 |
| H7%r | 1.5 | 1.5 | 1.5 | 1.9 |
| H9%r | 1.8 | 1.7 | 1.8 | 12.0 |
| H11%r | 2.7 | 2.6 | 2.7 | 5.1 |
| H13%r | 1.3 | 1.3 | 1.3 | 2.2 |
| H15%r | 2.0 | 2.0 | 2.0 | 14.7 |

09/01/04 11:29:43 277V 60Hz 3Ø WYE EN50160

At an average of 13.8% across all phases, this THD reading was way too high. He selected the Watts reading (W) to get an idea of what the K factor was for the transformer's derating.



K-factor measures the heating effects of harmonics on transformer loading and losses.

K-1 is the baseline for a standard transformer. K-4 would be four times the "normal" heating. K-rated transformers are specifically designed to handle harmonics.

Derating is a way of calculating the realistic load a transformer can carry when harmonics are present. For example, while a transformer may be rated at 150 kVA, harmonics would derate it to a 75 kVA load availability.

The higher the harmonics the less efficient the transformer is and the less current it can carry — the harmonics are competing for the total rating. In this case, the combination of customer load and harmonics had resulted in an overloaded transformer.

So, were the harmonics, too high or was the transformer insufficient? The technician began tracing the load. THD and K-factor are worst-case at the load vs. elsewhere in the distribution system. This is because source impedance is highest at the load, and source impedance is what drives THD and K-factor higher.

He realized that while the plant floor had been updated to include a full assortment of harmonic-laden electrical and electronic technology, the entire electrical system was still designed to support the original, 75 year-old electrical load.

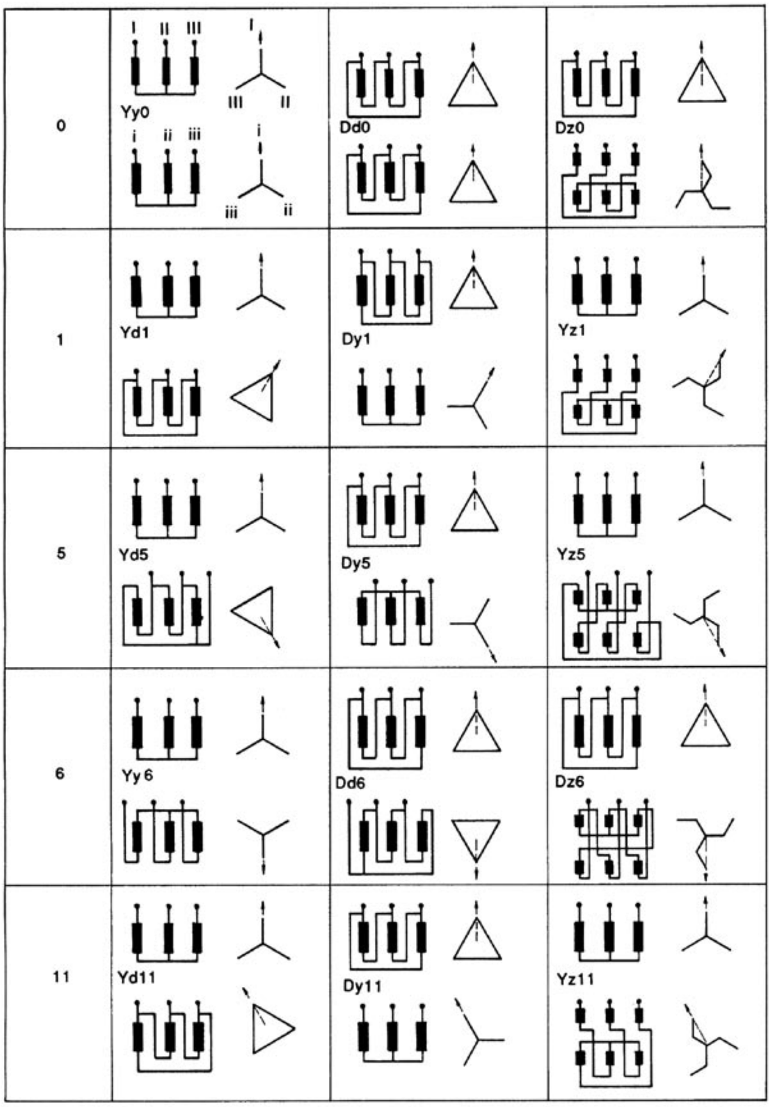
## CONCLUSION

Based on the harmonic levels and loading figures gathered by the power quality analyzer, the technician went to the floor manager and recommended a new K-rated transformer designed to support the real load for that production area.

In the meantime, he suggested either transferring some of the current load to other transformers or staggering the timing of the loads. He also recommended regular harmonics and system impedance measurements. The new transformer wouldn't overheat, but given the amount of harmonics on this system, they would have to consistently track THD throughout the floor.

# A Guide To Transformer DC Resistance Measurements

**Bruce Hembroff, CEFT, Manitoba Hydro Additions and Editing by Matz Ohlen and Peter Werelius, Megger**



IEC 265/93

Figure 1. Common 3-phase Transformer Connections

## 1 INTRODUCTION

Winding resistance measurements in transformers are of fundamental importance for the following purposes:

- Calculations of the I2R component of conductor losses;
- Calculation of winding temperature at the end of a temperature test cycle;
- As a diagnostic tool for assessing possible damage in the field.

Transformers are subject to vibration. Problems or faults occur due to poor design, assembly, handling, poor environments, overloading or poor maintenance. Measuring the resistance of the windings assures that the connections are correct and the resistance measurements indicate that there are no severe mismatches or opens. Many transformers have taps built into them. These taps allow ratio to be increased or decreased by fractions of a percent. Any of the ratio changes involve a mechanical movement of a contact from one position to another. These tap changes should also be checked during a winding resistance test.

Regardless of the configuration, either star or delta, the measurements are normally made phase to phase and comparisons are made to determine if the readings are comparable. If all readings are within one percent of each other, then they are acceptable. Keep in mind that the purpose of the test is to check for gross differences between the windings and for opens in the connections. The tests are not made to duplicate the readings of the manufactured device which was tested in the factory under controlled conditions and perhaps at other temperatures.

This application note is focusing on using winding resistance measurements for diagnostic purposes.

## 2 TRANSFORMER DC RESISTANCE MEASUREMENTS

### *2.1 AT INSTALLATION*

Risk of damage is significant

whenever a transformer is moved. This is inherent to the typical transformer design and modes of transportation employed. Damage can also occur during unloading and assembly. The damage will often involve a current carrying component such as the LTC, RA switch or a connector. Damage to such components may result in a change to the DC resistance measured through them. Hence, it is recommended that the DC resistance be measured on all on-load and off-load taps prior to energizing.

If the transformer is new, the resistance test also serves as a verification of the manufacturer's work.

Installation measurements should be filed for future reference.

## 2.2 AT ROUTINE (SCHEDULED) TRANSFORMER MAINTENANCE

Routine maintenance is performed to verify operating integrity and to assure reliability. Tests are performed to detect incipient problems. What kind of problems will the resistance test detect?

### 2.2.1 RATIO ADJUSTING SWITCH (RATIO ADJUSTING OFF-LOAD TAP CHANGER)

Contact pressure is usually obtained through the use of springs. In time, metal fatigue will result in lower contact pressure. Oxygen and fault gases (if they exist) will attack the contact surfaces.

Additionally, mechanical damage resulting in poor contact pressure is not uncommon. (E.g. A misaligned switch handle linkage may result in switch damage when operated). Such problems will affect the DC resistance measured through the RA switch and may be detected.

### 2.2.2 LOAD TAP CHANGER

The LTC contains the majority of the contacts and connections in the transformer. It is one of few non-static devices in the transformer and is required to transfer load current several thousand times a year. Hence, it demands special consideration during routine maintenance.

In addition to detecting problems associated with high resistance contacts and connectors, WINDAX-125 Winding Resistance Meter will also detect open circuits (drop-out test). LTCs transfer load current and are designed for make-before-break, they are NOT designed to interrupt load current. An open circuit would likely result in catastrophic failure. On installation and after maintenance it is certainly prudent to verify operating integrity by checking for open circuits. LTC maintenance often involves considerable disassembly and the test will provide confidence in the reassembly.

It is recommended DC resistance measurements be made on all on-load

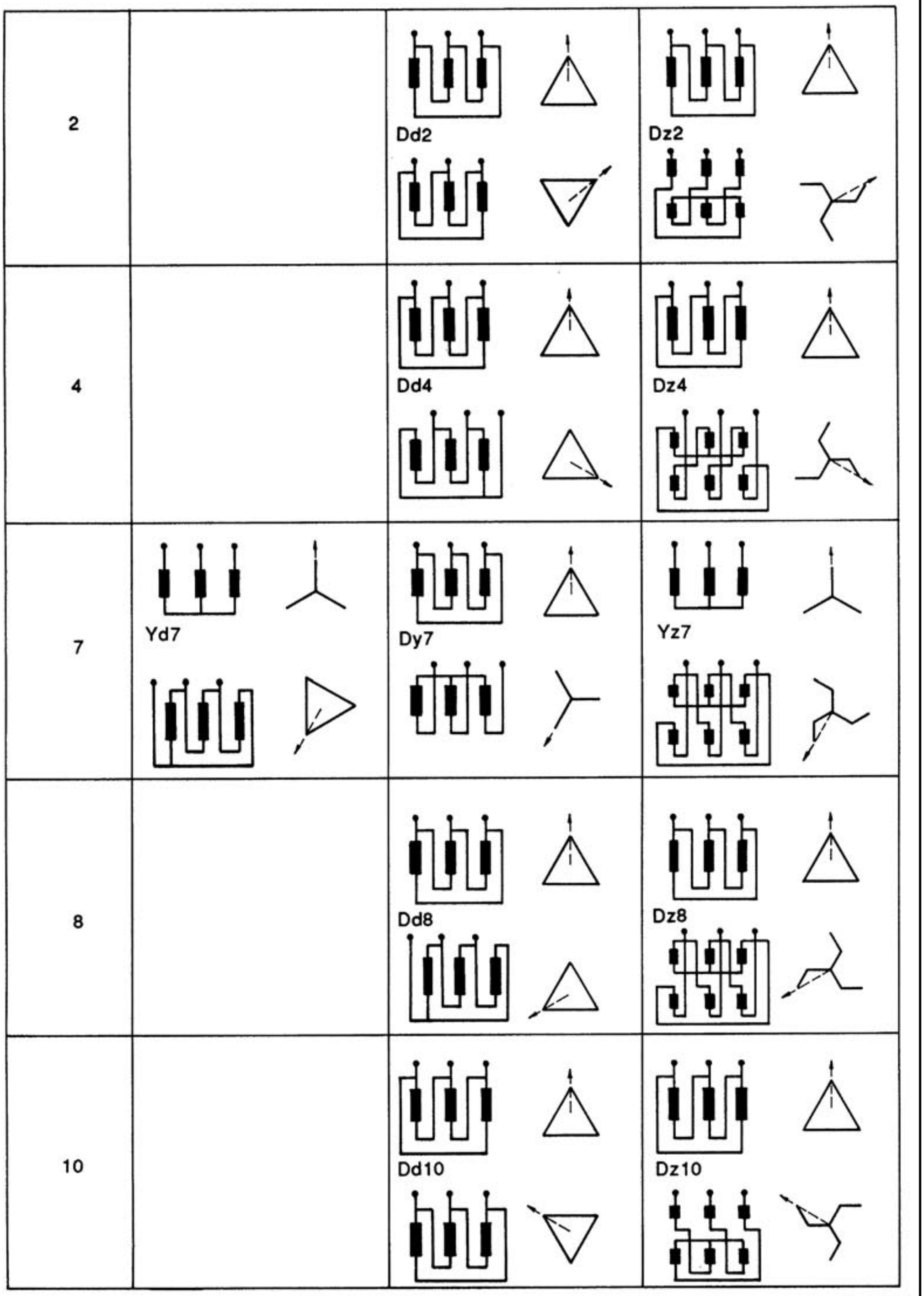


Figure 2. Alternative 3-phase Transformer Connections

IEC 266/93

and off-load taps to detect problems and verify operating integrity of the RA switch and LTC.

## *2.3 AT UNSCHEDULED MAINTENANCE/TROUBLESHOOTING*

Unscheduled maintenance generally occurs following a system event. The objectives of unscheduled maintenance are:

- To detect damage to the transformer;
- To determine if it is safe to re-energize;
- To determine if corrective action is necessary;
- To establish priority of corrective action.

Many transformer faults or problems will cause a change in the DC resistance measured from the bushings (shorted turns, open turns, poor joints or contacts). Hence, the information derived from the resistance test is very useful in analyzing faults or problems complimenting information derived from other diagnostic tests such as FRA, DRA (power factor), DGA and other measurements. The winding resistance test is particularly useful in isolating the location of a fault or problem and assessing the severity of the damage.

## *2.4 AT INTERNAL TRANSFORMER INSPECTIONS*

Internal inspections are expensive due primarily to the cost of oil processing. When such opportunities do present themselves, the inspection should be planned and thorough. Prior to dumping the oil, all possible diagnostic tests, including the resistance test, should be performed.

## 3 TEST EQUIPMENT

Prior to modern digital electronic equipment, the Kelvin Bridge was used. Batteries, switches, galvanometers, ammeters and slide-wire adjustments were used to obtain resistance measurements. Current regulators were constructed and inserted between the battery and the bridge. Input voltage to the regulator of 12 volts DC from an automobile storage battery provided output currents variable in steps which matched the maximum current rating of the bridge on the ranges most used on transformers. The current regulator increased both speed and accuracy of the bridge readings. The approximate 11 volt availability was used to speed up the initial current buildup and tapered off to about 5 volts just before

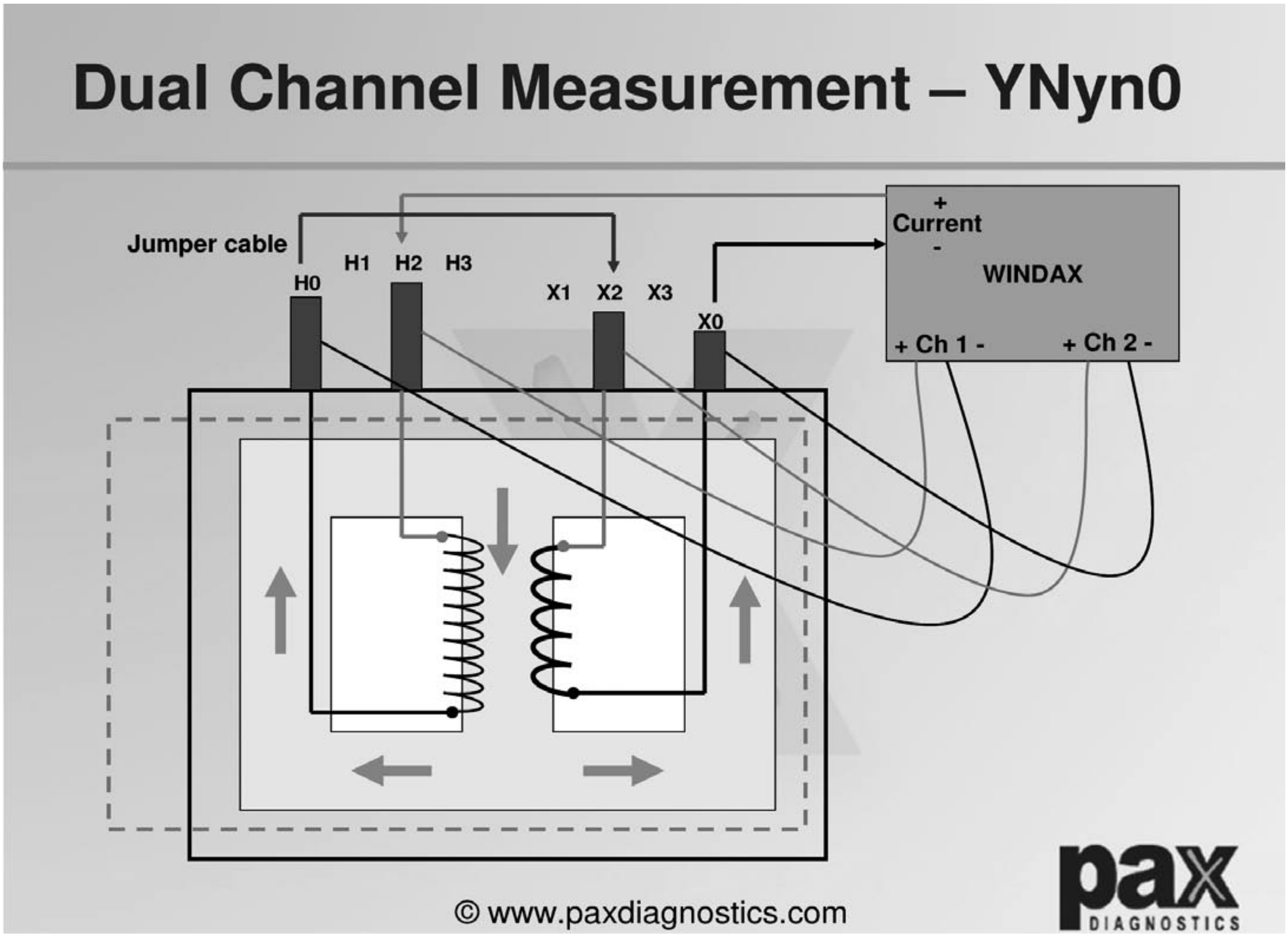


Figure 3. Measuring two windings simultaneously

the selected current was reached and regulation started. When the regulation began, the current was essentially constant in spite of the inductance of the windings and fluctuation of the battery voltage or lead resistance.

The testing times have been greatly reduced using modern microprocessor based test equipment.

Direct readings are available from digital meters with automatic indications telling when a good measurement is available. On some testers like the Pax WINDAX, two measurement channels are available allowing two resistance measurements at the same time.

## 4 SAFETY CONSIDERATIONS

While performing winding resistance tests, hazardous voltages could appear on the terminals of the transformer under test and/or the test equipment, if appropriate safety precautions are not observed.

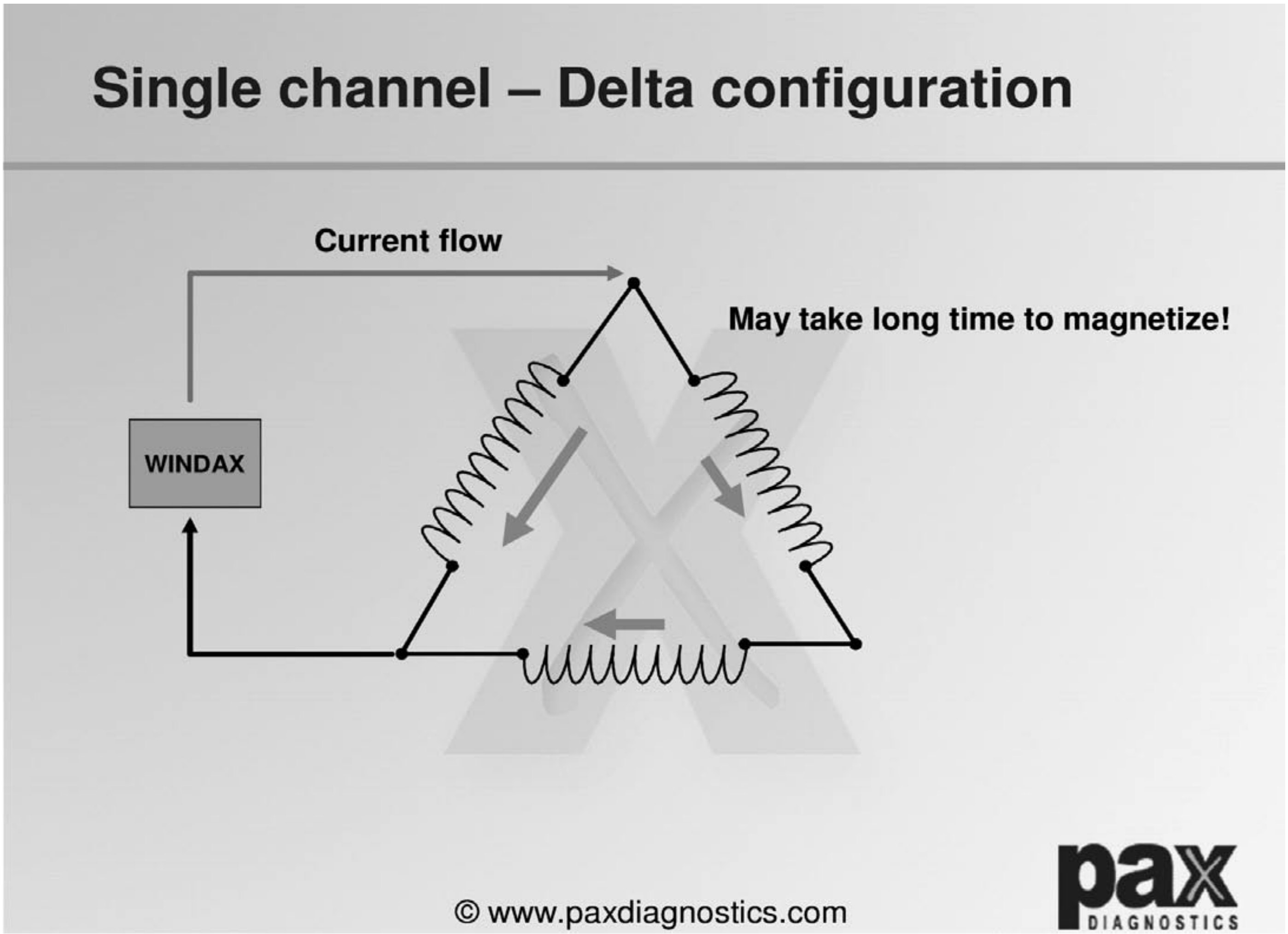
There are two sources to consider:

- AC induction from surrounding energized conductors; and
- The DC test current.

### *4.1 AC INDUCTION*

When a transformer is located in an AC switch yard in close proximity to energized conductors, it is quite probable an electrostatic charge would be induced onto a floating winding. This hazard can be eliminated by simply tying all windings to ground. However, to perform a winding resistance test only one terminal of any winding can be tied to ground. Grounding a second terminal will short that winding, making it impossible to measure the resistance of the winding. Two grounds on the winding under test would probably result in measuring the resistance of the ground loop. Two grounds on a winding which is not under test will create a closed loop inductor. Because all windings of a transformer are magnetically coupled, the DC test current will continually circulate within the closed loop inductor (the shorted winding). The instrument display would probably not stabilize, and accurate measurements would not be possible.

It does not matter which terminal is grounded, as long there is only one terminal of each winding tied to ground. When test leads are moved to subsequent phases or windings on the transformer, it



Single channel – Delta configuration

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**Figure 4. Closed delta winding**

is not necessary to move the ground connections. Ensure the winding is grounded prior to connecting the current and potential test leads, and when disconnecting leads remove the ground last.

### *4.2 DC TEST CURRENT*

Should the test circuit become open while DC current is flowing, hazardous voltages (possibly resulting in flash over) will occur. Care must be taken to ensure the test circuit does not accidentally become open:

- Ensure the test leads are securely attached to the winding's terminals;
- Do not operate any instrument control which would open the measured circuit while DC current is flowing. Discharge the winding first;
- Do not disconnect any test leads while DC current is flowing. Ensure the winding is discharged first;
- When terminating the test, wait until the discharge indicator on WINDAX goes off before removing the current leads. When testing larger transformers, it may take 30 seconds or more to discharge the winding. If a longer time (30 seconds plus) is required to charge a winding when the current is initiated, a corresponding longer time will be required to discharge the winding.

### *4.3 SUMMARY OF SAFETY PRECAUTIONS*

- Ensure all transformer windings and the test instrument chassis are grounded prior to connecting the test leads.
- Take appropriate precautions to ensure the test circuit is not opened while DC (test) current is flowing.

Failure to take appropriate precautions can result in hazardous potentials which could be harmful to both personnel and test equipment. It should be noted that transformer windings are essentially large inductors. The higher the voltage and the larger the (MVA) capacity, the higher the induction and hence the potential hazard.

## 5 SELECTING THE PROPER CURRENT RANGE

Transformer manufacturers typically recommend that the current output selected should not exceed about 10% of the rated winding current. This could cause erroneous readings due to heating of the winding (e.g. A transformer rated 1500 kVA, 1 ph: the rated current of the 33 kV winding is 45 amps; therefore the test current should not exceed 4.5 A. Do not select more than 4 A current output on WINDAX.)

Always choose the highest current output possible for the expected resistance value. Typical ranges are 0.1-10 % of rated winding current.

## 6 MEASUREMENTS

Wait until the display has stabilized prior to recording resistance values. Generally, readings on a star-configured transformer should stabilize in 10-30 seconds. However, the time required for readings to stabilize will vary, based on the rating of the transformer, the winding configuration, output voltage of the test instrument and the current output selected. On large transformers with high inductance windings, it could take a few minutes for readings to stabilize.

For large transformers with delta configuration, magnetization and getting stable readings can take significantly longer time, sometimes as long as 30-60 minutes (see Figure 4). If the readings don't stabilize within the maximum measurement time, check leads, connections and instrument. It may be necessary to reduce the test current and inject current on HV and LV windings simultaneously (recommended!), see sections 7.3 and 11, table 1.

- Record measurements as read. Do not correct for temperature. (When using the WINDAX PC SW, automatic re-calculation to normalized temperature can be done without changing the original test record). Do not calculate individual winding values for delta connected transformers.
- Record DC test current selected.
- Record unit of measure (ohms or milli-ohms).
- Review test data. Investigate and explain all discrepancies.

As a general rule, the first measurement made is repeated at the end of the test. Consistent first and last readings give credibility to all measurements. Whenever an unexpected measurement is obtained, the test method and procedure is questioned. If the measurement can be repeated, the doubt is removed. In situations where time is of concern, the repeat measurement can be omitted if all measurements are consistent.

Always check the winding schematic on the nameplate, and trace the current path(s) through the windings. The nameplate vector representation may be misleading. Also, check the location of grounds on the windings and ensure the grounds do not shunt the DC test current.

When a winding has both an RA switch (ratio adjusting off-load tap changer) and an LTC (load tapchanger) take measurements as follows:

- With the LTC on neutral measure resistance on all off-load taps.
- With the RA switch on nominal/rated tap measure resistance on all on-load taps.

### *6.1 RA SWITCH MEASUREMENTS*

The recommended procedure for testing RA switches is as follows:

- Prior to moving the RA switch measure the resistance on the as found tap. Note: This measurement is particularly useful when investigating problems.
- Exercise the switch by operating it a half dozen times through full range. This will remove surface oxidization. See "Interpretation of Measurements - Confusion Factors".
- Measure and record the resistance on all off-load taps.
- Set the RA switch to the as left tap and take one final measurement to ensure good contact. Do not move the RA switch after this final measurement has been made.

### *6.2 LTC MEASUREMENTS*

As found measurements are performed for diagnostic purposes in both routine and non-routine situations. As left measurements are performed to verify operating integrity following work on the LTC. The resistance test on a transformer with an LTC is time consuming; hence the value of the as found test in each particular situation should be evaluated. Consider maintenance history and design. Certainly, if the proposed work involves an internal inspection (main tank) or a problem is suspected, the as found test should be performed.

Prior to taking as left measurements, exercise the LTC. Operat-

**Table 1. Transformer Connection Schemes for measuring two windings simultaneously**

| IEC Vector Group | Transformer Configuration | | | | | | |
|---|---|---|---|---|---|---|---|
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dd0** | **Delta** | | | **Delta** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H3-X1 | X3 | H1 | H3 | X1 | X3 |
| 2 | H2 | H1-X2 | X1 | H2 | H1 | X2 | X1 |
| 3 | H3 | H2-X3 | X2 | H3 | H2 | X3 | X2 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dyn7** | **Delta** | | | **Y with neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H3-X0 | X1 | H1 | H3 | X0 | X1 |
| 2 | H2 | H1-X0 | X2 | H2 | H1 | X0 | X2 |
| 3 | H3 | H2-X0 | X3 | H3 | H2 | X0 | X3 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dyn1** | **Delta** | | | **Y with neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H3-X1 | X0 | H1 | H3 | X1 | X0 |
| 2 | H2 | H1-X2 | X0 | H2 | H1 | X2 | X0 |
| 3 | H3 | H2-X3 | X0 | H3 | H2 | X3 | X0 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **YNyn0** | **Y with neutral** | | | **Y with neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H0-X1 | X0 | H1 | H0 | X1 | X0 |
| 2 | H2 | H0-X2 | X0 | H2 | H0 | X2 | X0 |
| 3 | H3 | H0-X3 | X0 | H3 | H0 | X3 | X0 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Ynd1** | **Y with neutral** | | | **Delta** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H0-X1 | X2 | H1 | H0 | X1 | X2 |
| 2 | H2 | H0-X2 | X3 | H2 | H0 | X2 | X3 |
| 3 | H3 | H0-X3 | X1 | H3 | H0 | X3 | X1 |

ing the LTC through its full range of taps two to six times should remove the surface oxidation.

When testing windings with LTCs, use the tap-changer setup on WINDAX to ensure that the measurement value for each tap is stored separately. The current generator is on throughout the test sequence while changing from tap to tap. With respect to the number of consecutive tests to perform, SW operation and data storage is recommended. However WINDAX can perform TC testing

**Table 1. Transformer Connection Schemes for measuring two windings simultaneously (continued)**

| IEC Vector Group | Transformer Configuration | | | | | | |
|---|---|---|---|---|---|---|---|
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dy1** | **Delta** | | | **Y without neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H3-X1 | X2 | H1 | H3 | X3 | X2 |
| 2 | H2 | H1-X2 | X3 | H2 | H1 | X1 | X3 |
| 3 | H3 | H2-X3 | X1 | H3 | H2 | X2 | X1 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **YNd7** | **Y with neutral** | | | **Delta** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H0-X2 | X1 | H1 | H0 | X2 | X1 |
| 2 | H2 | H0-X3 | X2 | H2 | H0 | X3 | X2 |
| 3 | H3 | H0-X1 | X3 | H3 | H0 | X1 | X3 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dyn5** | **Delta** | | | **Y with neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H2-X0 | X1 | H1 | H2 | X0 | X1 |
| 2 | H2 | H3-X0 | X2 | H2 | H3 | X0 | X2 |
| 3 | H3 | H1-X0 | X3 | H3 | H1 | X0 | X3 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dy11** | **Delta** | | | **Y without neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H2-X1 | X3 | H1 | H2 | X1 | X3 |
| 2 | H2 | H3-X2 | X1 | H2 | H3 | X2 | X1 |
| 3 | H3 | H1-X3 | X2 | H3 | H1 | X3 | X2 |
| IEC Vector Group | Transformer Configuration | | | | | | |
| | High-Voltage Winding (H) | | | Low Voltage Winding (X) | | | |
| **Dyn11** | **Delta** | | | **Y with neutral** | | | |
| Test # | Current Connections | | | Meas ch 1 | | Meas ch 2 | |
| | + Current | Jumper | - Current | + | - | + | - |
| 1 | H1 | H2-X1 | X0 | H1 | H2 | X1 | X0 |
| 2 | H2 | H3-X2 | X0 | H2 | H3 | X2 | X0 |
| 3 | H3 | H1-X3 | X0 | H3 | H1 | X3 | X0 |

stand-alone.

Measure the resistance for first tap. Operate TC. Measure resistance for second tap, resistance value and current ripple for the previous tap change is stored. Operate TCS. Measure resistance for third tap etc.

Should the LTC open the circuit and cause current interruption, WINDAX will automatically stop and go into its discharge cycle indicated by the discharge LED. This gives the operator a clear indication by a panel light of a possible fault within the tap changer. Such transformers should not be returned to service as catastrophic failure would be possible.

## 7 CONNECTIONS

### *7.1 GENERAL*

Prior to connecting the instrument leads to the transformer all transformer windings must be grounded. See Safety Considerations. Make connections in the following order:

1. Ensure winding terminals are not shorted together and tie to ground (the transformer tank) one terminal only of each transformer winding (i.e. both the winding to be tested as well as those not being tested). Note: It does not matter which terminal is grounded (a line terminal or neutral) as long as only one terminal on each winding is grounded. There is no need to move the ground as the test progresses to measuring subsequent phases or windings.

2. Ensure the instrument's power switch is in the OFF position and connect it to the mains supply. Note: The instruments chassis is grounded through the supply cable to the station service. (On occasion it has not been possible to stabilize the display when the instrument's chassis ground was not connected to the same ground point as the winding (i.e., the transformer tank). This problem is most likely to occur when the station service ground is not bonded to the transformer tank and is easily remedied by connecting a jumper between the instrument chassis and the transformer tank.

3. Connect the current and potential leads to the instrument.

4. Connect the current and potential leads to the transformer winding. The potential leads must be connected between the current leads. Do not clip the potential leads to the current leads. Observe polarity.

5. Upon completion of the test, ensure the winding is discharged before disconnecting any test leads. Remove the ground from the transformer winding last. Caution: Do not open the test circuit in any way (i.e. disconnecting test leads, or operating the current selector switch) while DC current is flowing. Hazardous voltages (probably resulting in flash-over) will occur.

### *7.2 WYE WINDINGS*

Refer to Figures 1-3 and Table 1. Measuring two windings simultaneously is possible if a suitable common test current can be selected. Take resistance measurements with the indicated connections.

Connecting the test equipment as per Figure 3 is the preferred method because it allows the operator to measure two phases simultaneously. Compared to measuring each phase individually, there is a significant time saving particularly when measuring a winding with an LTC. Alternately, if the instrument will not energize both windings simultaneously, measure one winding at a time.

If time is of concern, the last test set up, which is a repeat of the first, may be omitted if all measurements are consistent when comparing one phase to the next or to previous tests.

### *7.3 Delta Windings*

Refer to Figures 1-2 and Table 1. If possible, always inject test current to HV and LV (and measure two windings) simultaneously. This will magnetize the core more efficiently and shorten the time to get stable readings. If single-injection single-channel measurement is chosen, please note that the time for stabilization on larger transformers may be long!

Take resistance measurement with the indicated connections. Again, if time is of concern, the last test set up, which is a repeat of the first, may be omitted if all measurements are consistent when comparing one phase to the next or to previous tests.

## 8 INTERPRETATION OF MEASUREMENTS

Measurements are evaluated by:

- Comparing to original factory measurements;
- Comparing to previous field measurements;
- Comparing one phase to another.

The latter will usually suffice. The industry standard (factory) permits a maximum difference of 1/2 percent from the average of the three phase windings. Field readings may vary slightly more than this due to the many variables. If all readings are within one percent of each other, then they are acceptable.

Variation from one phase to another or inconsistent measurements can be indicative of many different problems:

- Shorted turns;
- Open turns;
- Defective ratio adjusting (RA) switch or LTC;
- Poor connections (brazed or mechanical).

The winding resistance test is very useful in identifying and isolating the location of suspected problems.

### *8.1 Confusion Factors*

Apparent problems (i.e., inconsistent measurements or variations between phases) can also be the result of a number of factors which are not indicative of problems at all. Failure to recognize these factors when evaluating test data can result in confusion and, possibly, unwarranted concern.

### *8.1.1 Temperature change*

The DC resistance of a conductor (hence winding) will vary as its temperature changes, for copper windings 0.39 % per degree C. This is generally not a significant consideration when comparing one phase to another of a power transformer. Loading of power transformers is generally balanced, hence temperatures should be very similar. However, when comparing to factory measurements or previous field measurements, small but consistent changes should be expected. In addition to loading, temperature variations (likewise resistance variations) can be due to:

- Cooling or warming of the transformer during test. It is not uncommon for one to two hours to pass between taking a first and last measurement when testing a large power transformer with an LTC. A transformer which has been on load can have a significant temperature change in the first few hours off- load.
- When measuring the DC resistance of smaller transformers, care should be exercised to ensure that the test current does not cause heating in the winding. The test current should not exceed 10 percent of the windings rating.

When using the WINDAX PC SW, automatic re-calculation to normalized temperature can be done and the recalculated value is reported together with the measured value.

### *8.1.2 CONTACT OXIDIZATION*

The dissolved gases in transformer oil will attack the contact surfaces of the RA switch and LTC.

The problem is more prevalent in older transformers and heavily loaded transformers. Higher resistance measurements will be noticed on taps which are not used. (Typically a load tapchanger installed on a subtransmission system will only operate on 25-50 per cent of its taps.) This apparent problem can be rectified by merely exercising the switch. The design of most LTC and RA switch contacts incorporate a wiping action which will remove the surface oxidization. Hence, operating the switch through its full range 2 to 6 times will remove the surface oxidization.

A potential transformer installed in one phase could become part of the measured circuit and affect the measured DC resistance of that phase.

A two winding CT installed in one phase would have a similar effect. Usually donut bushing type CTs are used in power transformers. However, on rare occasions an in-line two winding CT may be encountered.

### *8.1.3 A MEASURING ERROR*

There are many possibilities:

- A wrong connection or poor connection;
- A defective instrument or one requiring calibration;
- An operating error;
- A recording error.

### *8.1.4 AMBIGUOUS OR POORLY DEFINED TEST DATA*

There is often more than one way to measure the resistance of a transformer winding (e.g., line terminal to line terminal or line to neutral). Typically, field measurements are taken from external bushing terminals. Shop or factory measurements are not limited to the bushing terminals.

Additionally, internal winding connections can be opened (e.g. opening the corner of a delta), making measurements possible which are not practical in the field. Details of test set-ups and connections area often omitted in test reports which can lead to confusion when comparing test data.

### *8.2 HOW BAD IS BAD?*

When a higher than expected measurement is encountered what does it mean? Is failure imminent?

Can the transformer be returned to service? Is corrective action needed? To answer these questions, more information along with some analytical thinking is usually required.

- Firstly, have the confusion factors been eliminated?
- Secondly, what are the circumstances which initiated the resistance test? Was it routine maintenance or did a system event (e.g. lightning or through fault) result in a forced outage?
- Is other information available? Maintenance history? Loading? DGA? Capacitance bridge? Excitation current? If not do the circumstances warrant performing additional tests?
- Consider the transformer schematic. What components are in the circuit being measured?
- Has the location of the higher resistance been isolated? See "Isolating Problems".
- How much heat is being generated by the higher resistance?

This can be calculated (I2R) using the rated full load current. Is this sufficient heat to generate fault gases and possibly result in catastrophic failure? This will depend on the rate at which heat is being generated and dissipated. Consider the mass of the connector or contact involved, the size of the conductor, and its location with respect to the flow of the cooling medium and the general efficiency of the transformer design.

## 9 ISOLATING PROBLEMS

The resistance test is particularly useful in isolating the location of suspected problems. In addition to isolating a problem to a particular phase or winding, more subtle conclusions can be drawn.

Consider the transformer schematic (nameplate). What components are in the test circuit? Is there an RA switch, LTC, diverter isolating switch, link board connectors, etc.? By merely examining the test data, problems can often be isolated to specific components. Consider:

### *9.1 RA SWITCH*

In which position does the higher resistance measurement occur? Are repeat measurements (after moving the RA switch) identical to the first measurement or do they change.

### *9.2 LTC*

The current carrying components of the typical LTC are the step switches, reversing switch and diverter switches. Carefully examine the test data looking for the following observations:

### *9.2.1 STEP SWITCH OBSERVATION*

A higher resistance measurement occurring on a particular tap position both boost and buck (e.g., both +1 and-1, +2 and -2, etc.)

The above observation would indicate a problem with a particular step switch. Each step switch is in the circuit twice-once in the boost direction and once in the buck direction.

### *9.2.2 REVERSING SWITCH OBSERVATION*

All boost or buck measurements on a phase are quantatively and consistently higherthan measurements in the opposite direction or other phases.

The reversing switch has two positions, buck and boost, and operates only when the LTC travels through neutral to positions +1 and -1. Hence, a poor contact would affect all boost or buck measurements. If the LTC is operated between +1 and -1, the resistance measured through a poor reversing switch contact would likely change.

### *9.2.3 DIVERTER SWITCH OBSERVATION*

All odd step or all even step measurements in both the buck and boost direction are high.

There are two diverter switches. One is in the current circuit for all odd steps and the other for all even steps.

The foregoing discussion is only typical. LTC designs vary. To draw conclusion based on resistance measurements, the specific LTC schematic must be examined to identify the components which are being measured on each step. This information is usually available on the transformer nameplate.

### *9.3 CONTACTS VS CONNECTORS OR JOINTS*

Is the higher resistance measurement consistent and stable when the RA switch or LTC is operated? Generally, inconsistent measurements are indicative of contact problems while a consistent and stable high measurement would point to a joint or connector.

## 10 LIMITATIONS

The transformer resistance test has several limitations which should be recognized when performing the test and interpreting test data:

The information obtained from winding resistance measurements on delta connected windings is somewhat limited. Measuring from the corners of a closed delta the circuit is two windings in series, in parallel with the third winding (see Figure 4).

The individual winding resistances can be calculated; however this is a long tedious computation and is generally of little value. Comparison of one 'phase' to another will usually suffice for most purposes. Additionally, since there are two parallel paths an open circuit (drop out) test does not mean too much. However, the test is still recommended. Problems involving LTCs and RA switches will yield measurements which are not uniform, and often unstable and inconsistent.

Hence the resistance test will detect most problems.

The resistance of the transformer's winding can limit the effectiveness of the test in detecting problems. The lower the resistance of a winding, the more sensitive the test is with respect to detecting problems. Windings with high DC resistance will mask problems.

The detection of shorted turns is not possible in all situations. Often shorted turns at rated AC voltage cannot be detected with the DC test. If the fault is a carbon path through the turn to turn insulation, it is a dead short at operating potentials. However, at test potential, 30 V DC, the carbon path may be a high resistance parallel path and have no influence on the measured resistance. Certainly if the conductors are welded together the fault should be detectable.

It is not possible on some transformer designs to check the LTC using the resistance test (e.g., series winding). The circuit between external terminals simply excludes the LTC. On such units, the resistance test is of no value in verifying the operating integrity of the LTC. If the LTC selector switch is in the main tank (i.e., same tank as windings) and cannot be physically inspected, it is recommended that samples for DGA be taken as part of routine LTC maintenance.

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# Pressure Relief Valve Efficiency Calculations During Transformer Short-circuit

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## 1 INTRODUCTION

The work undertaken by the SERGI Research Department led to the development of the Magneto-Thermo-Hydrodynamics (MTH) Model. The theoretical results of the MTH model were published for the first time in July 1999 [1]. Experimental checks were carried out in collaboration with a transformer manufacturer, FRANCE TRANSFO, SCHNEIDER Group, and the results were published subsequently [2]. Today, the MTH Model is an invaluable aid to the design and sizing of the transformer explosion and fire prevention system developed by SERGI and known as TRANSFORMER PROTECTOR. This article deals with the application of the MTH model to the case of Pressure Relief Valves.

Pressure Relief Valves have always protected transformer tanks. However, all exploded transformers were equipped with this protection. Their performance rests on the response time, the depressurization speed and the capacity to maintain a low pressure inside the tank during short-circuit. SERGI has therefore undertaken a study to verify their dynamic behaviour for pressure gradients calculated during low impedance faults.

The SERGI research program managed to determine pressure gradients generated during transformer explosions.

Depending on short-circuit location and on the amount of energy transferred to the oil, the tank internal pressure increases by 0.05 to 1 bar per millisecond. The particularly severe case of power plant transformer explosion was extensively studied in order to design a system that would be suitable for any case of explosion. The pressure gradients calculated for the power plant step-up transformers in publication [3] were applied to the TRANSFORMER PROTECTOR and the Pressure Relief Valve in order to compare their performances.

The mechanical dynamic study

of the Pressure Relief Valve enabled SERGI to determine the spring inertia and energy losses depending on its design and on the pressure gradient inside the transformer. The Pressure Relief Valve fluid sections and energy losses due to its "U" geometry were calculated for various opening heights.

Lastly, the finite element analysis enabled SERGI to understand and quantify its hydraulic behaviour while subjected to different pressure gradients and throughout depressurization.

The TRANSFORMER PROTECTOR was also the subject of a complete study including mechanical and hydraulic finite element analysis of a whole depressurization. Those studies determine the Decompression Set performances including its Rupture Disk opening function, according to geometry and physical material properties. Calculation details have not been published; they are confined in a SERGI Research Department document available just for well-known experts, organizations or consulting companies [4].

The TRANSFORMER PROTECTOR and Pressure Relief Valve efficiencies were then studied on the basis of three different types of insulation rupture, published in article [3]. This publication deals with 35KA, 118KA and 236KA faults that generate pressure slopes of 0.1, 2 and 2.3 bar/millisecond at the time of the tank explosion (1.2 bars).

## 2 SIMULATION PARAMETERS AND DEFINITIONS

### *2.1 FAULT DURATION*

All carried out finite element analyses consider a permanent fault feeding during 80 millisecond, which corresponds to the opening time of conventional circuit breakers. The gas production is thus continuous during the depressurization process. The Pressure Relief Valve and TRANSFORMER PROTECTOR inertia play a cornerstone role as the pressure continues to evolve in all simulation configurations.

### *2.2 SIZING OF THE PRESSURE RELIEF VALVE AND TRANSFORMER PROTECTOR*

Two parameters play an important role in over-pressure protection system, the "Nominal Diameter" and the "Operational Pressure Set Point":

- The "Nominal Diameter" represents the supposed oil evacuation diameter. This designed section can be very different from the operational section when the dynamic behaviour of the protection system is analyzed;
- The "Operational Pressure Set Point" is the pressure level chosen for the protection system to start the depressurization process.

### 2.3 DEPRESSURIZATION PARAMETERS DEFINITION

There are three key parameters used by the SERGI Research Department that are used to compare the performances of the different TRANSFORMER PROTECTOR sizes, for a given transformer and pressure gradient:

- The "Maximum Reached Pressure" in the transformer tank after the system activation;
- The "Operation Time";
- The "Depressurization Time".

These definitions have also been applied to the Pressure Relief Valve for its behaviour comparison with the TRANSFORMER PROTECTOR:

- The Maximum Reached Pressure in the transformer tank after the system activation shows the mechanical protection ability to instantaneously defuse the pressure gradient. This calculation is of utmost importance.

One needs to compare the Maximum Reached Pressure to the tank pressure withstand limit. This value mainly depends on the mechanical protection inertia to act at full flow capacity. In other words, the Maximum Reached Pressure, after depressurization process has started, can be the cause of tank explosions, should the system inertia be too great.

- The Operation Time is the time lapse between the moment when the pressure relief device first starts to open and the moment when it reaches full opening.
- The Depressurization Time corresponds to the time required to bring the tank pressure back to atmospheric pressure starting at the mechanical protection operation initiation. This value integrates the system inertia, the hydraulic properties and the oil quantity to be evacuated.

## 3 PRESSURE RELIEF VALVE DYNAMIC STUDY

Pressure Relief Valves were designed 30 years ago in order to avoid tank explosions consecutive to insulation faults. Today, transformer explosions and resulting fires are frequent, although all tanks are equipped with Pressure Relief Valves. The research conducted on the Pressure Relief Valve began with a bibliographical investigation and documentation survey. Surprisingly, neither article nor suppliers calculation on the Pressure Relief Valves dynamic behaviour was discovered or provided. However, several articles referred to the incapacity of Pressure Relief Valves to depressurize transformer tanks subjected to violent fault [6], [7] and [8].

Each fault type is defined by pressure gradients for each Operational Pressure Set Point at the time of activation of both prevention systems.

Firstly, a mechanical study of the Pressure Relief Valve enabled SERGI to determine the spring dynamics and inertia, which depend on the material and pressure gradient in the transformer. The useful fluid evacuation section and energy losses due to the Pressure Relief Valve "U" geometry were calculated for various openings and oil velocities. The results of this study, enhanced by the depressurization pressure loss calculation, enabled SERGI to define the Pressure Relief Valve efficiency and limits.

### *3.1 DESCRIPTION*

The Pressure Relief Valve role is to limit transformer internal pressures by freeing a certain fluid quantity.

Pressure Relief Valves are located on tank covers or sidewalls. Their activation relies on the opening of an Operating Disk (4) compressed by a Single or a Double Springs (2) that can be adjusted to open at different preset operating pressures.

Pressure Relief Valve technologies scarcely vary from one size of transformer to another. They are designed to open when pressure reaches a certain predetermined threshold. This Operational Pressure Set Point depends on the force applied by the spring on the Operating Disk (4), therefore the amount of springs and their mechanical properties.

With reference to Figure 1 and Figure 2,

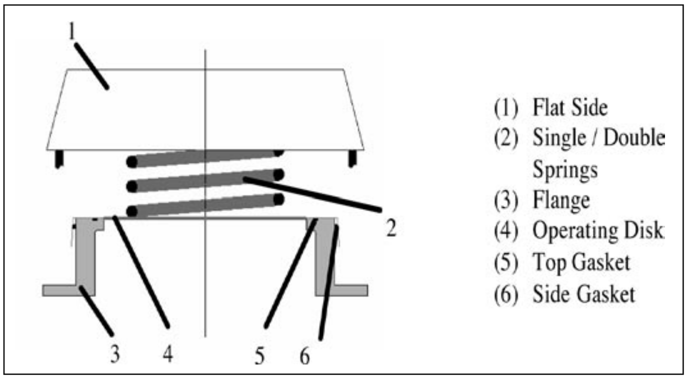

**Figure 1: Single Spring Pressure Relief Valve**

the oil pressure in the transformer acts on the tight Operating Disk (4) maintained closed by the Single or Double Springs (2). When the overpressure exceeds the Operational Pressure Set Point, the Operating Disk (4) separates from the Top Gasket (5). Then, oil is spread over a second surface, more significant than the first, whose sealing is ensured by the Side Gasket (6). The pressure, which applies to the second surface, generates a higher force and accelerates the opening.

## 3.2 CALCULATION

### *3.2.1 PRESSURE RELIEF VALVE EVACUATION SECTION*

The Pressure Relief Valve opening is mainly accomplished in two movements corresponding to two thrust surfaces whose sealing is ensured by the Top Gasket (5) and the Side Gasket (6). However, its U-shape geometry imposes the opening of the Operating Disk (4) in several stages, presented in the following graph:

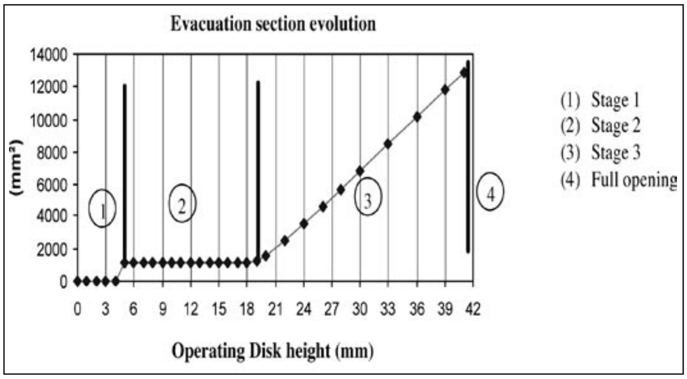

**Figure 3: Evacuation section evolution**

- Stage 1 (0-4mm): The fluid evacuation section is here equal to zero for the first 4mm, because of the Operating Disk square angle shape (4) and Side Gasket (5).
- Stage 2 (4-18mm): When the Side Gasket allows fluid evacuation the section remains constant until the Operating Disk (4) lower level is higher than the top of the Flange (3), which corresponds to the height of 18 mm, that is to say 44% of the maximum height. During stage 2, the evacuation section is the equivalent of 15% of the maximum evacuation section.
- Stage 3 (18-41mm): During 56% of the maximum height, the evacuation section is progressive up to the full opening.

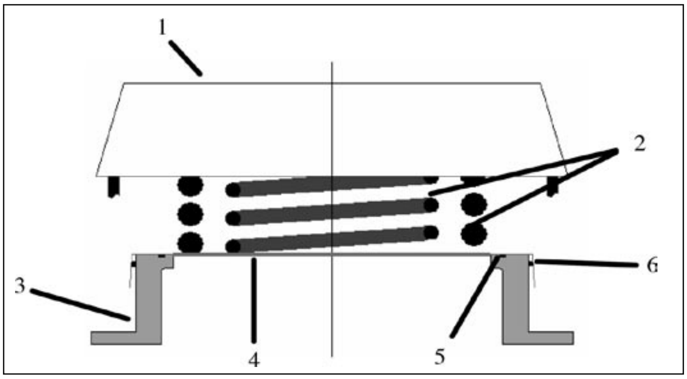

**Figure 2: Double Spring Pressure Relief Valve**

- Stage 4 (41mm): The Pressure Relief Valve full opening, maximum height, is 41mm. However, the full opening does not correspond to the 150mm Nominal Diameter, as the evacuation section is, in fact, limited to a 128mm diameter, that is to say 85% of the Nominal Diameter.

From this simple analysis, one emphasizes that the Pressure Relief Valve:

- Is physically open only when a fluid evacuation is possible, that is to say after a 4mm lift, introducing an important lap time at the beginning of the depressurisation process, in addition to the spring inertia;
- Evacuation section represents only 15% of the Nominal Diameter during 44% of the opening maximum height;
- Nominal Diameter of 150mm is in fact limited to a diameter of 128mm.

### *3.2.2 PRESSURE RELIEF VALVE INERTIA*

The characteristics of the Operating Disk (4) opening depend on the spring physical and mechanical properties.

Its stiffness is a key parameter. It defines the opening speed and the opening pressure. Some Pressure Relief Valves are designed with Double Springs (2), which can be compared to a Single Spring (2) of equivalent stiffness. The Pressure Relief Valve studied for this test is equipped with only one spring and calibrated at 0.35 bar.

The determination of the Operating Disk (4) movement equations enables to trace its height versus time, while considering the spring stiffness and mechanical properties.

Height attained versus time $$H_d = \frac{PS_2}{k}\left(1 \square \cos\left(t\sqrt{\frac{k}{m}}\right)\right)$$

t: Time in second
P: Pressure in Pascal
Hd: Operating Disk height in meter
m: Operating Disk mass, 0.5kg
S2: Operating Disk total surface in m2, 0.025446
k: Spring resistance, 12 415.571 N/m

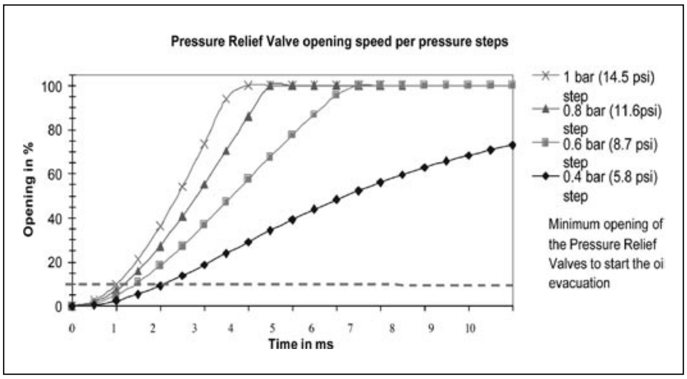

Figure 4: Operating Disk height versus time and pressure

The graph shown above represents the Operating Disk opening evolution versus time for different pressure steps.

The first 4mm of lift represent a delay of 2 to 4 milliseconds for pressure steps ranging from 0.4 bar to 1 bar. The spring dynamic behaviour plays a paramount role in the Pressure Relief Valve operation. The spring inertia is the cause of a lap time delay in the Operating Disk opening. The minimum opening time of a Pressure Relief Valve is approximately 3 milliseconds whatever the pressure gradient applied in the tank is.

### *3.2.3 PRESSURE LOSS CALCULATION*

The following figures point out the fact that the "U" shape geometry of the Operating Disk and cover of the valve represent a considerable obstacle to the fluid evacuation. It is therefore necessary to calculate pressure loss characteristics in the valve for different Operating Disk heights.

The Operating Disk and internal walls of the valve flange limit the oil volume in the valve.

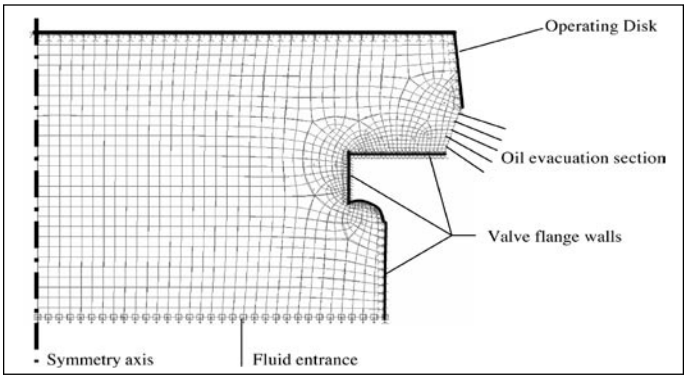

Figure 5: Pressure Relief Valve structure and meshing

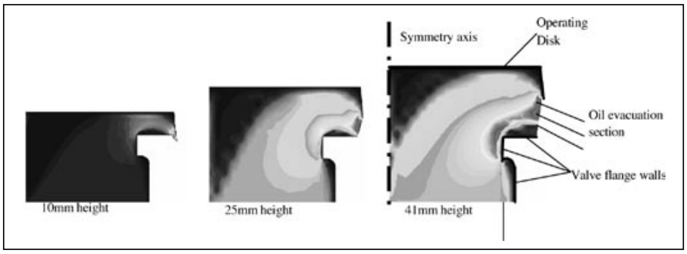

Figure 6: Pressure Relief Valve finite element analysis and pressure loss evaluation for different opening heights

The exhaust velocity and evacuation sections define an oil volume flow depending on the Operating Disk opening time. The evacuated oil flow for each pressure step is calculated by integrating the different exhaust velocities to the Pressure Relief Valve opening curves.

The SERGI Research Department assumes that the Pressure Relief Valve evacuates the fluid in a homogeneous way on its entire periphery. The pressure losses can be calculated using the Bernoulli formula between the Pressure Relief Valve input and the output.

$$\frac{P_1}{?} + \frac{v_1^{\,2}}{2} = \frac{P_2}{?} + \frac{v_2^{\,2}}{2} + ?P$$

The energy losses are determined by the following formula:

$$\square P = ? * \frac{?\,V^2}{2}\,\frac{L}{D}$$

The linear pressure loss ratio is calculated according to the flow type. All cases are studied under turbulent flow conditions.

The mass and volume conservation equations resolution determines the average oil velocities at Pressure Relief Valve output:

$$v_2^{\,2}\left[1 \square \left(\frac{S_{eq}}{S_1}\right)^2\right] + v_2^{1.75}\left[0.316\left(\frac{S_{eq}}{S_1}\right)^{1.75}\frac{?\,L}{\vartheta^{\square 0.25}}D_{eq}^{\square 1.25}\right] = \frac{2P_{(t)}}{\rho}$$

Exhaust velocities at the exit of the evacuation sections define an oil flow depending on the Operating Disk opening time.

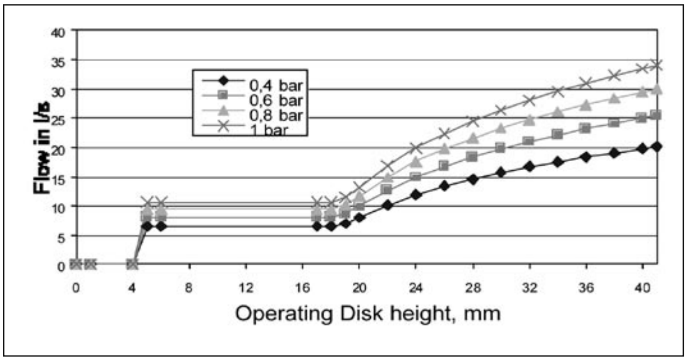

Figure 7: Evacuated flow versus Pressure Relief Valve opening

### 3.3 CONCLUSION

The Pressure Relief Valve design and "U" shape geometry lead to important pressure losses, which greatly reduces the flow and restrains the oil expulsion outside tanks. The evacuation surface of a half-opened Pressure Relief Valve represents only 15 percent of its maximum surface. The spring inertia also leads to a very penalizing opening delay.

In addition, the Pressure Relief Valve closes when the pressure decreases, therefore favouring a second overpressure should the fault remain or should the gas production endure.

It must be noted that pollutant oil and self-flammable gases are evacuated on the faulted transformer cover, therefore propagating the fire to other components of the installation.

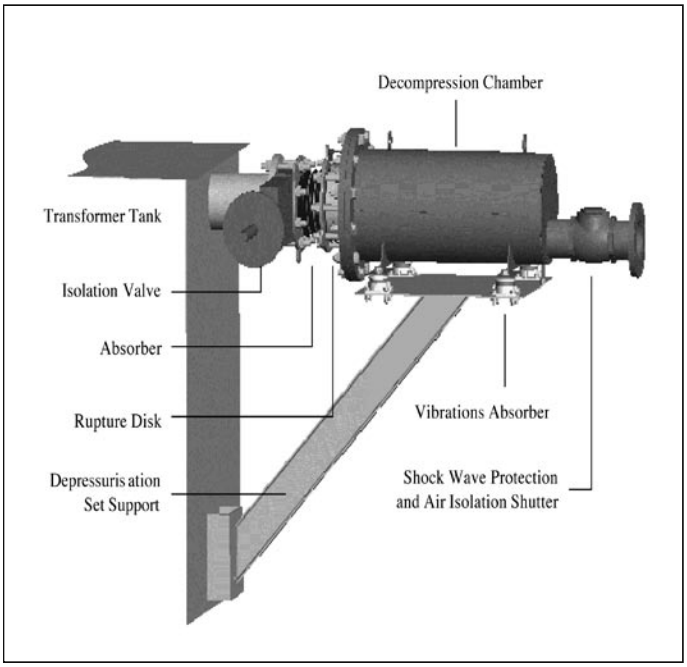

Figure 8: TRANSFORMER PROTECTOR Depressurization Set

## 4 DYNAMIC STUDY OF THE TRANSFORMER PROTECTOR

### *4.1 PRESENTATION*

The TRANSFORMER PROTECTOR was the subject of a complete study including mechanical and hydraulic finite element analysis. Those finite element analyses determined the opening function, the system response time according to pressure gradients and energy losses during the oil evacuation.

- The Isolation Valve is a vacuum-proof gate valve integrated to the system in order to keep the control of the evacuation section. It enables to isolate the transformer from the TRANSFORMER PROTECTOR during installation, maintenance or a field operation;
- The Absorber is a 3-wave bellows provided with vacuum holder reinforcement inner rings and outer holding rings for overpressures. This element reduces the mechanical stress transmitted to the Rupture Disk by transformer vibrations or pipe expansion;
- The Rupture Disk is made of stainless steel and reinforced to withstand vacuum. The Rupture Disk Operational Pressure Set Point varies according to its use. When pressure reaches the preset operation value, the Rupture Disk opens and depressurizes the transformer;
- The Decompression Chamber favours the depressurization by enabling the evacuated oil-gas mixture created by a rupture of insulation without creating any "plug" effect.

### *4.2 Calculations*

#### 4.2.1 TRANSFORMER PROTECTOR inertia

In order to avoid the most unfavourable tank explosions, the Decompression Set integrated Rupture Disk is designed to be fully opened in a lap time ranging from 0.5 to 2.5 millisecond, depending on the pressure gradient, which follows an insulation rupture.

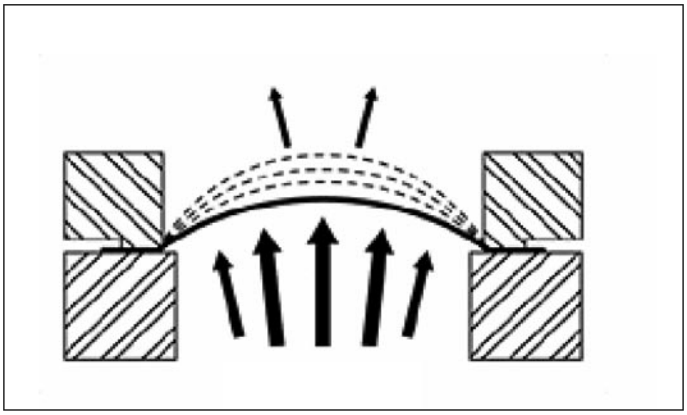

Figure 9: Disk opening principle

The stainless steel Rupture Disk Operational Pressure Set Point for the TRANSFORMER PROTECTOR can be different according to its use. The Rupture Disk opens when the Operational Pressure Set Point is reached and liberates the fluid excess out of the tank.

The performances of the SERGI Rupture Disk were determined after a large series of calculations, simulations and tests. This has been compulsory to determine the best protection conception, with the goal of preventing tank explosion consecutive to severe faults. Only the main results are presented here along with the calculation details of energy losses.

Research on the behaviour and opening time of the Rupture Disk was undertaken by SERGI. The results were applied to real explosion cases [2] and [3]. The Rupture Disk full opening time versus fault is given here below:

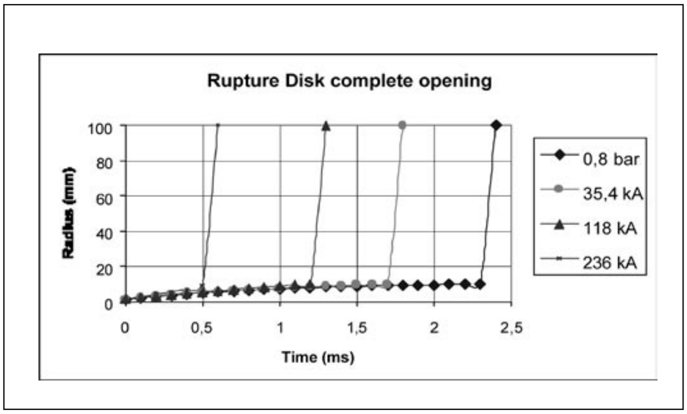

Figure 10: Rupture Disk full opening for different faults

The Rupture Disk opening time depends on the fault type and varies from 0.6 millisecond for a strong short circuit to 1.8 milliseconds for a weak short circuit.

| Fault type | Rupture Disk opening time in millisecond |
|---|---|
| Operation shock, 35KA | 1,8 |
| Electric shock, 118KA | 1,2 |
| Lightning shock, 236KA | 0,6 |

Table 1: Rupture Disk response versus fault type

#### 4.2.2 PRESSURE LOSS

The Depressurization Set Decompression Chamber offers an integral fluid channel, favouring oil evacuation.

However, pressure losses of each component were considered in the depressurization calculation.

$$v_a S_a = v_b S_b$$

$$\square\frac{P_a}{?g}+\frac{v_a^{2}}{2g}+h_a=\frac{P_b}{?g}+\frac{v_b^{2}}{2g}+h_b+\square P$$

Pressure loss calculations are based on matter conservation and Bernoulli laws described here above. The Pressure loss in the Depressurization Set corresponds to the sum of each component individual pressure loss.

Those are determined separately and then integrated in the

$$v_2^{2}=\frac{2}{?}\square\frac{P_0\square P_2}{\square 1+\frac{3.3}{4}+\square\frac{S_2}{S_1}\square^{2}\square\square\frac{L_{valve}\,f_{valve}}{D}+\frac{L_{pipe}\,f_{pipe}}{D}+0.001+k_{absorber}\square 1\square}$$

The following Figure 11 highlights the importance of each elem

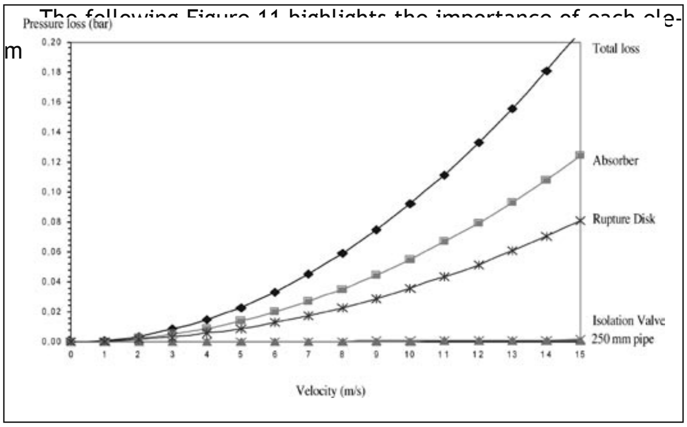

Figure 11: TRANSFORMER PROTECTOR pressure loss per element

The following Figure 12 highlights the consequences of a Rupture Disk partial opening on the oil evacuation speed. Only the losses corresponding to a TRANSFORMER PROTECTOR in the openin

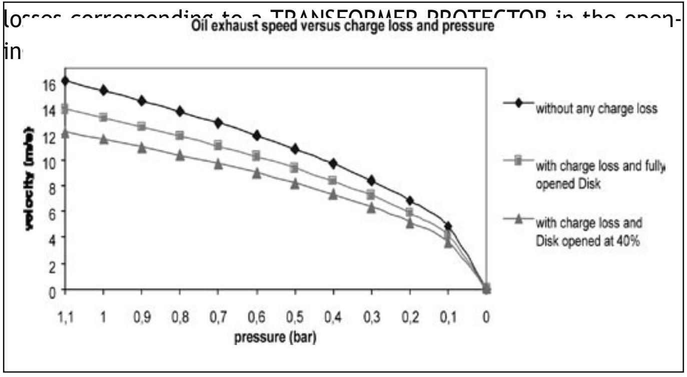

Figure 12: Oil evacuation speed versus tank pressure

### *4.3 Conclusion*

The TRANSFORMER PROTECTOR Decompression Chamber is designed to minimize the pressure losses in the Depressurization Set. The Rupture Disk material choice and geometry favour a depressurization in a few milliseconds, therefore preventing pressure increase above the tank maximum tolerated pressure.

The role of the Decompression Chamber is to:

- Favour the oil-gas mixture expansion;
- Prevent plug phenomena that could take place in uniform piping by applying the properties of the "Venturi" effect for the oil-gas mixture evacuation;
- Prevent eventual secondary overpressures that could appear after depressurisation when gases are still produced by the fault energy [3].

In addition, the TRANSFORMER PROTECTOR presents a cornerstone advantage since it is reactive to pressure. The stronger the pressure gradient is, the quicker the Rupture Disk opens and the faster the transformer tank pressure decreases.

## 5 COMPARATIVE RESULTS BETWEEN PRESSURE RELIEF VALVE AND TRANSFORMER PROTECTOR

### *5.1 COMPARISON PARAMETERS*

The TRANSFORMER PROTECTOR and Pressure Relief Valve share the common role of depressurizing transformer tanks in case of internal faults. However, their technology and efficiency differ. In the previous paragraphs, the influence of the Pressure Relief Valve alone and of the TRANSFORMER PROTECTOR alone have been studied for each fault.

Here, the systems are subjected to the same incidents in order to compare their performances. However, the "Operational Pressure Set Points" are chosen in order to favour the Pressure Relief Valve. It was assumed that its operational pressure set point is of 0.35 bar. The TRANSFORMER PROTECTOR Pressure Set Point is settled at 0.8 bar. Consequently, more time is given to the Pressure Relief Valve to act on the tank pressure. In addition, the pressure gradients are much weaker at 0.35 bar than at 0.8 bar.

Transformer tank pressure withstand limit is 1.2 bars.

In order to compare their performances, the TRANSFORMER PROTECTOR and Pressure Relief Valve efficiency comparison was performed for three different faults on a 150MVA OFAF transformer.

- Operation shock: 35.4 kA;
- Electric shock: 118 kA;
- Lightning shock: 236 kA.

### *5.2 MECHANICAL AND HYDRAULIC COMPARISON*

#### 5.2.1 Evacuation section equivalent diameter comparison for a Nominal Diameter of 150 mm

Figure 13 shows the evacuation section diameter evolution versus opening time when both protections have a Nominal Diameter of 150 mm and are subjected to a 0.8 bar step.

Pressure Relief Valve and TRANSFORMER PROTECTOR have a 150mm nominal diameter. The valve evacuation surface is brought down to an equivalent disk surface.

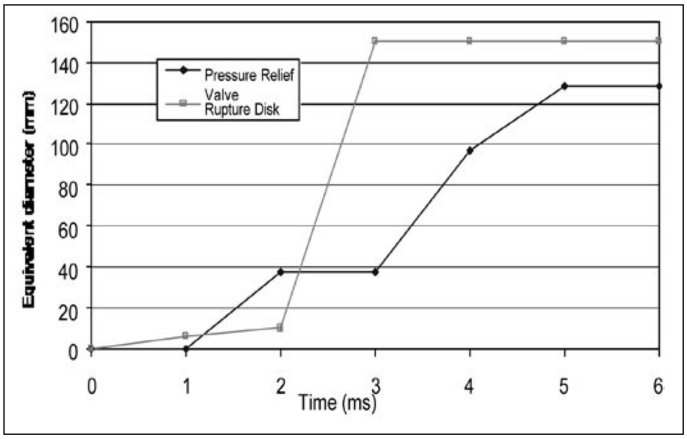

Figure 12: Evacuation section diameter comparison for a nominal section of 150 mm

The Pressure Relief Valve evacuation section is comparable to a partial cone which maximum area corresponds to 72.8% of the nominal surface.

The Pressure Relief Valve equivalent maximum evacuation diameter corresponds to 90% of its nominal diameter at full opening. The rupture disk of identical Nominal Diameter has a greater evacuation section than the Pressure Relief Valve. In this configuration, the fastest Pressure Relief Valve complete opening time (5ms) is twice as slow as the slowest Rupture Disk opening time.

### 5.2.2 FLOW COMPARISON

Flows are calculated for 4 different Rupture Disk Nominal Diameters and for the biggest Pressure Relief Valve Nominal Diameter available on the market. The following graph presents the e

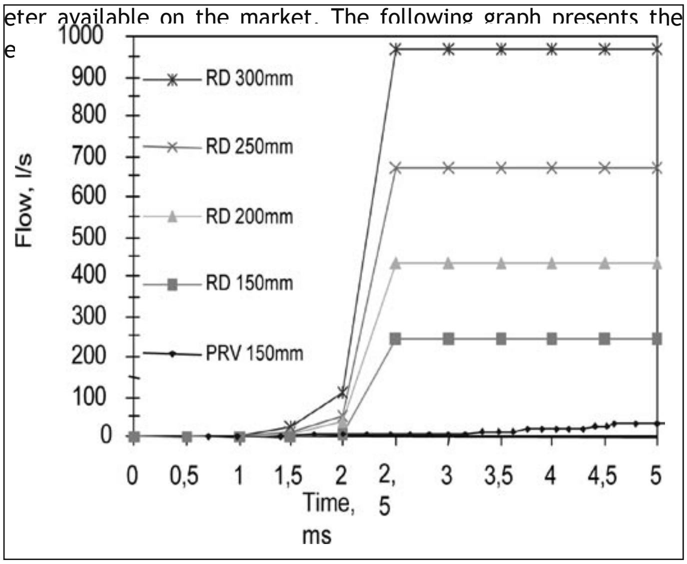

Figure 13: Flow comparison for 0.8 bar inside the transformer tank

The Pressure Relief Valve oil flow reaches its maximum after 5 ms, against 2.5 ms for the TRANSFORMER PROTECTOR. The evacuated oil quantity per millisecond is eight times more important with a Rupture Disk than with a Pressure Relief Valve of the same Nominal Diameter. In other words, the flow of a 150mm Nominal Diameter Decompression Chamber is equal to that of 8 Pressure Relief Valves of the same Nominal Diameter. The flow of 300mm Nominal Diameter Decompression Chamber is equal to 30 Pressure Relief Valves of 150mm Nominal Diameter.

If Figure 13 pictures the inertia of the systems, Figure 14 emphasizes the energy losses. The proof is here given that the Pressure Relief Valve design and "U" shape geometry lead to important pressure losses, which greatly reduces the flow and restrains oil expulsion.

## *5.3 APPLICATION TO THREE DIFFERENT TRANSFORMER FAULTS*

### *5.3.1 Comparison parameters*

In order to compare their performances, the TRANSFORMER PROTECTOR and Pressure Relief Valve efficiency comparison was performed for three different faults on a 150MVA OFAF transformer:

- Operation shock: 35.4 kA;
- Electric shock: 118 kA;
- Lightning shock: 236 kA.

The effects on the transformer tank pressure of the different protections are reported in the following paragraphs.

The performance parameters, as described in paragraph 2, are recorded for each fault:

- The Maximum Reached Pressure;
- The Operation Time.

Then, the result comparison is made on Table 2.

### *5.3.2 Operation shock: 34,5 kA Fault*

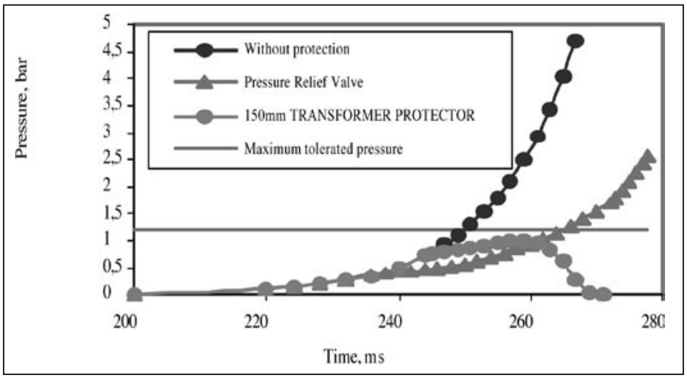

Figure 14: Pressure evolution following a 34,5 kA fault

One notes that the Pressure Relief Valve only opens at 0.4 bar, even if its Operational Pressure Set Point is 0.35 bar. Therefore, its Operation Time is approximately 14 milliseconds. Even for this "small" short circuit, the Pressure Relief Valve protected transformer tank explodes about 30 milliseconds later than if it was not protected at all.

With the TRANSFORMER PROTECTOR, the Maximum Reached Pressure is 0.98 bar, about 20% below the tank pressure withstand limit.

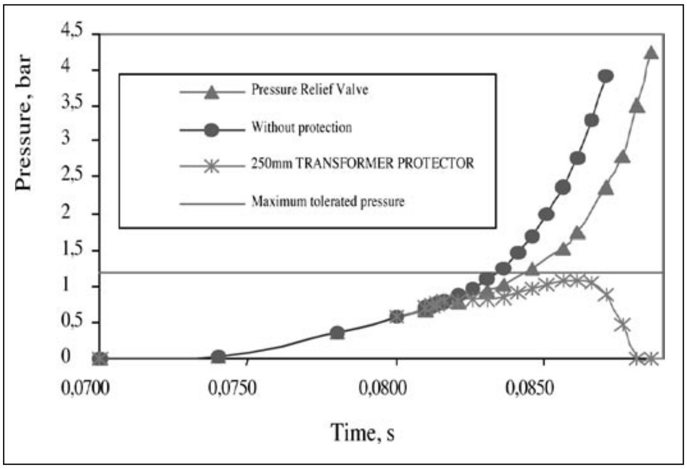

**Figure 15: Pressure evolution following a 118kA fault**

### *5.3.3 Electric shock: 118kA Fault*

One notes that the Pressure Relief Valve only opens at approximately 0.8 bar, even if its Operational Pressure Set Point is 0.35 bar. Its Operation Time is approximately of 4.3 milliseconds. Therefore, the Pressure Relief Valve protected transformer tank explodes about 7.5 milliseconds later than if it was not protected at all.

With the TRANSFORMER PROTECTOR, the Maximum Reached Pressure is 1.09 bars, around 10% below the tank pressure withstand limit.

### *5.3.4 Lightning shock: 236 kA Fault*

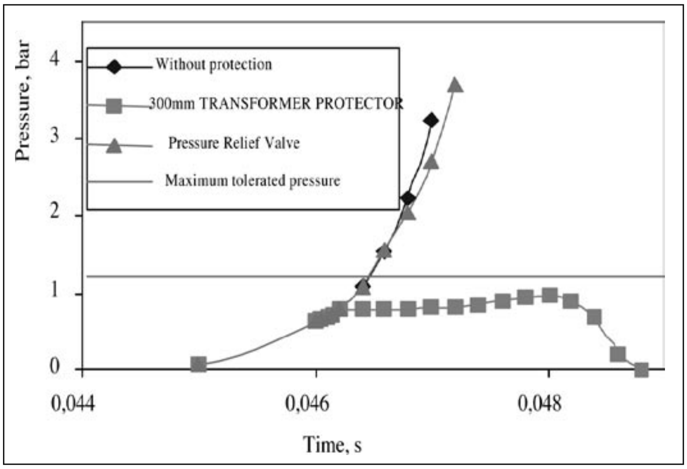

**Figure 16: Pressure evolution following a 236kA fault**

One notes that the Pressure Relief Valve only opens at approximately 2 bars, that is to say after the transformer tank has exploded. This explains why some publication authors have noted that in several incidents the Pressure Relief Valve had not activated at all. Its Operation Time is approximately of 2.2 milliseconds for that strong a pressure gradient. For the same incident, the TRANSFORMER PROTECTOR Operation Time is of 0.6 millisecond.

With the TRANSFORMER PROTECTOR, the Maximum Reached Pressure is 1.04 bars, around 15% below the tank pressure withstand limit.

### *5.4 Analysis*

The following table compares the Pressure Gradient, Operation Time and Maximum Reached Pressure of the Pressure Relief Valve and the TRANSFORMER PROTECTOR for each fault case.

| Low Impedance Fault kAmps | Pressure Relief Valve | | | TRANSFORMER PROTECTOR | | |
|---|---|---|---|---|---|---|
| | Pressure Gradient at activation Bar/Millisecond | Operation Time Millisecond | Maximum Reached Pressure Bar | Pressure Gradient at activation Bar/Millisecond | Operation Time Millisecond | Maximum Reached Pressure Bar |
| 35 kA operation shock [3] | 0.038 | 14 | Tank explosion | 0.06 | 1.8 | 0.98 |
| 118 kA electric shock [3] | 0.12 | 4.3 | Tank explosion | 0.13 | 1.2 | 1.09 |
| 236 kA lightning shock [3] | 0.54 | 2.2 | Tank explosion | 0.93 | 0.6 | 1.04 |

**Table 2: Rupture Disk and Pressure Relief Valve response versus fault type**

This study considers the Pressure Relief Valve to be pre-set at 0.35 bar, therefore placing it in favourable operating conditions. Pressure gradient values at the instant of valve activation are 0.038, 0.12 and 0.54 bar per millisecond for 35, 118 and 236kA arcs. For the same incidents, the TRANSFORMER PROTECTOR activates at 0.8 bar with pressure gradients of 0.06, 0.13, 0.93 bar per millisecond, which are nearly the double of the values given for the Pressure Relief Valve.

In every case, both protections activate but the Pressure Relief Valve is unable to save the transformer. One of the key parameter is the Operation Time. The Pressure Relief Valve does not stand the comparison with the TRANSFORMER PROTECTOR Depressurization Set in terms of Operation Time. The delay induced by this parameter in the Pressure Relief Valve case clearly lessens its efficiency. Considering that transformer tanks only withstand pressure below 1.2 bars, then in each simulated fault case the Pressure Relief Valve only delays the pressure increase in the transformer without preventing its explosion. This is due to the Pressure Relief Valve inertia and "U" shape geometry, which leads to important pressure losses.

The passing of this limit (1.2 bars) happens at 266, 84 and 46.5 milliseconds after fault appearance, which is respectively 28, 7 and 0.8 milliseconds after crossing the 0.35 bar Operational Pressure Set Point. This short time enables the Pressure Relief Valve to fully open in the first and second case. In the last case, the Operating Disk only rise below 4 mm and Pressure Relief Valve has no time to open. The depressurization therefore can not be assured and the tank explodes before the Pressure Relief Valve enters in operation.

In the first two cases, the pressure gradients are weak. The Pressure Relief Valve opens and due to its "U" shape geometry, a minor volume of oil is evacuated, not important enough to evacuate the required oil quantity. The flow only delays the explosion but does not prevent it. In the same conditions, the TRANSFORMER PROTECTOR is capable of depressurizing the tank, therefore preventing the explosion within 25 and 6 milliseconds respectively.

The last case corresponds to the most severe case. It shows that the Pressure Relief Valve has no time to open before tank explosion at 1.2 bars. Its inertia is such that it has no effect on the pressure before the transformer explodes. The TRANSFORMER PROTECTOR depressurizes the tank and prevents the explosion in only 2.7 milliseconds.

## *6 CONCLUSION*

The Pressure Relief Valve inertia considerably slows down the fluid evacuation during faults. The pressure loss and the small opening section of the valve strongly limit its efficiency to evacuate the gathered energy in a transformer subjected to slow, nearly static, pressure evolutions. Its efficiency is therefore limited to punctual faults of very weak pressure gradients.

The TRANSFORMER PROTECTOR Decompression Chamber geometry favours the fluid evacuation by reducing pressure losses. Moreover, it is designed to offer an integral fluid passage therefore not leading to an oil flow slowdown. The TRANSFORMER PROTECTOR is always operational in less than 2.5 milliseconds.

Therefore, depressurization is immediate, limiting internal pressure below the transformer tank maximum withstand pressure.

However, SERGI does not recommend users to get rid of the transformer Pressure Relief Valve, as it is useful for oil temperature variation effects moderating and to avoid overpressure mistakes during transformer maintenance or oil refilling.

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# Single And Three-phase Transformer Testing Using Static Motor Circuit Analysis Techniques

By Howard W. Penrose, Ph.D. on behalf of ALL-TEST Pro, LLC, Old Saybrook, CTand IEEE

## INTRODUCTION

Field and shop testing of pole and pad mount transmission and distribution (T&D) transformers can be costly and time consuming. With the onset of utility generation deregulation across the country, T&D becomes a greater issue due to varying power demands and power quality. A simple test method for quickly and accurately testing the condition of T&D equipment is a necessity as, if a transformer fails, both the end user and generating facility will complain. Through the use of an existing technology, originally designed for motor winding testing, an initial transformer evaluation can be performed.

For conceptual reasons, consider that an AC induction electric motor is a transformer with a rotating secondary. In this way, the capabilities that static Motor Circuit Analysis (MCA) provides an electric motor can be extended to a transformer. These include detecting winding shorts, high resistance connections, open windings and insulation to ground fault detection as well as preliminary internal circuit impedance balance. Specific information on the transformer is not required for most applications of MCA because the test equipment is used as a winding comparator.

An MCA device which provides readings of resistance, impedance, inductance, phase angle and a special test called current/frequency response (I/F) has been applied to transformers, for the purposes of this paper. Because the test method is off-line, the MCA device generates its own voltage and frequency output. Therefore, the ALL-TEST IV Pro™ 2000 motor circuit analyzer was selected. This unit weighs under 2 lbs, is handheld, and has a proven track record with AC/DC motors and generators from fractional to over 10 MW.

The first set of transformers tested included pole and pad mount transmission and distribution transformers from a few kVA to over 2500 kVA with primary voltage ratings of 480 Volts to 28.8kV. Following initial testing and analysis, procedures were developed to allow for general testing of any type of pole and pad mount transformer with a simple resistance greater than 0.001 Ohms. The results included the capability of testing the primary and secondary of any type of transformer in about 5 to 10 minutes with a greater than 99% success rate on either wet or dry-type transformers.

## BASIC TRANSFORMER CONCEPTS

To understand the basic concepts of a transformer, we shall start with an ideal transformer, or a theoretical transformer that has no losses. The purpose of the transformer is to convert one level of voltage and current to another level of voltage and current for distribution and application purposes. This is achieved by having a primary winding located close to secondary winding and allowing for mutual induction to occur between the windings.

When a sine-wave voltage is applied to the primary windings, a magnetic field is established that expands and contracts based upon the applied frequency. This field interacts with the secondary winding, producing a voltage within the secondary that is directly proportional to the turns ratio, while current is inversely proportional to the turns ratio.

Equation 1: Voltage Turns Ratio

$$N1 / N2 = a$$

Where N1 is the number of turns in the primary and N2 is the number of turns in the secondary Equation 2:

Current Turns Ratio

$$N2 / N1 = 1/a$$

For example, an ideal transformer with 100 turns in the primary and 50 turns in the secondary, with 480 Volts applied to the primary and a 100 amp load on the secondary would have: a voltage turn ratio of 2; a current turn ratio of 2; a 480 V1, 50 A1 load reflected on the primary and a 240 V2, 100 A2 load on the secondary.

Equation 3: Load Impedance

$$Z_L = V_2 / I_2$$

Equation 4: Equivalent Primary Impedance

$$Z^1_L = a^2 Z_L$$

Equations 3 and 4 can be used to reference the impedance from the secondary to primary. This can also be used inversely. Internal impedance can be matched to load impedance as found in Equation 5.

Equation 5: Internal Impedance

$$Z_S = a^2 Z_L = Z^1_L$$

In a real transformer there are certain losses, including core losses (hysterisis and eddy-currents), the magnetizing current, and leakage. In addition, supply voltage and load currents may have harmonic loads and other issues that would impact the effectiveness of a transformer. The purpose of static MCA is to reduce or eliminate these issues to isolate transformer testing.

## TRANSFORMER TYPES AND CONNECTIONS

Transformers of both single and three phase have a variety of connection types for a variety of loads. In a three-phase circuit, these connections are: Wye-Delta; Delta-Wye; Delta-Delta; and Wye-Wye. Single-phase, pole mounted transformers normally have a single-winding primary with a two-winding or center-tapped secondary.

Three-phase transformer connections are developed for a variety of applications:

1. Delta-Delta: Lighting and power applications, normally used when power loads are greater than lighting loads.
2. Open-Delta: Lighting and power applications, used when lighting loads are greater than power loads.
3. Wye-Delta: Power applications, used when stepping power up in voltage (i.e.: 2400 to 4160 Volts).
4. Wye-Delta: Lighting and power applications.
5. Open Wye-Delta: Will allow 57% capacity if one phase is disabled.
6. Delta-Wye: Normally provides a 4-wire on the secondary which allows for balanced single-phase loads between neutral and each phase.

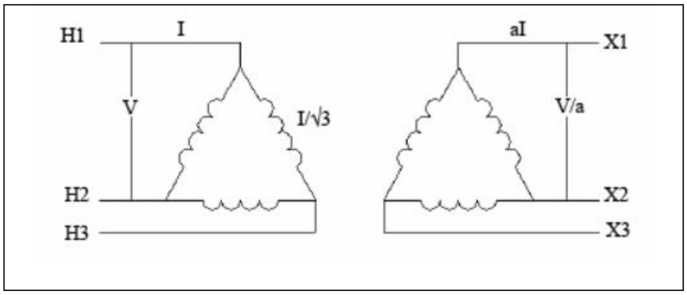

Figure 1: Delta-Delta Transformer

Three phase transformer connections are labeled H1, H2, and H3 on the primary and X1, X2, X3, with X0 as the neutral, on the secondary.

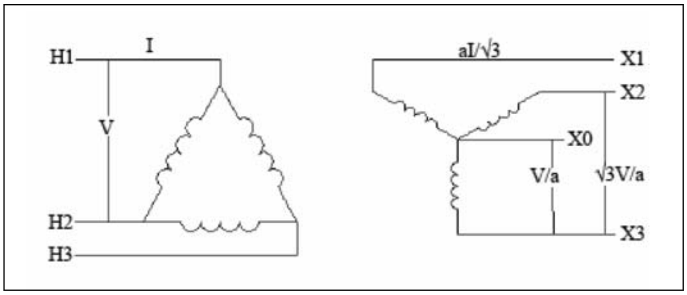

Figure 2: Delta-Wye Transformer

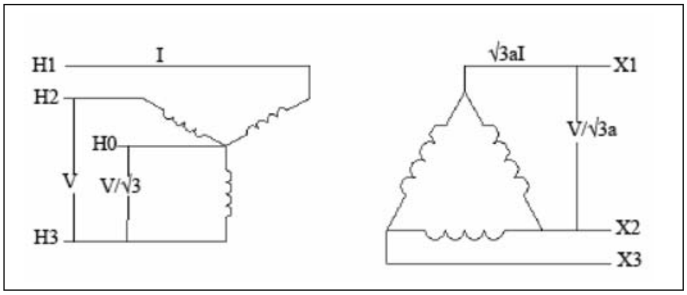

Figure 3: Wye-Delta Transformer

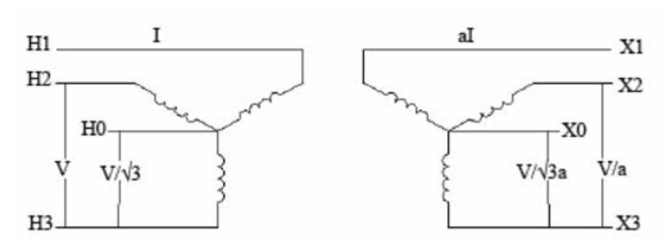

Figure 4: Wye-Wye Transformer

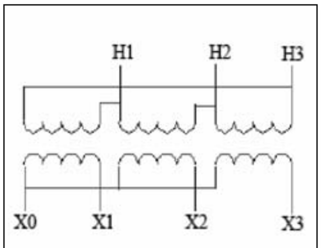

Figure 5: Delta-Wye Transformer Connection

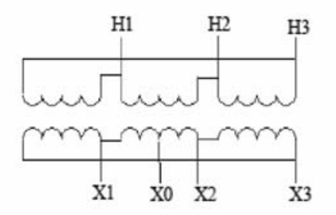

Figure 6: Delta-Delta Transformer Connection

Single-phase pole mounted transformers are often connected and labeled H1 and H2 on the primary and X1, X2 (center tap), and X3.

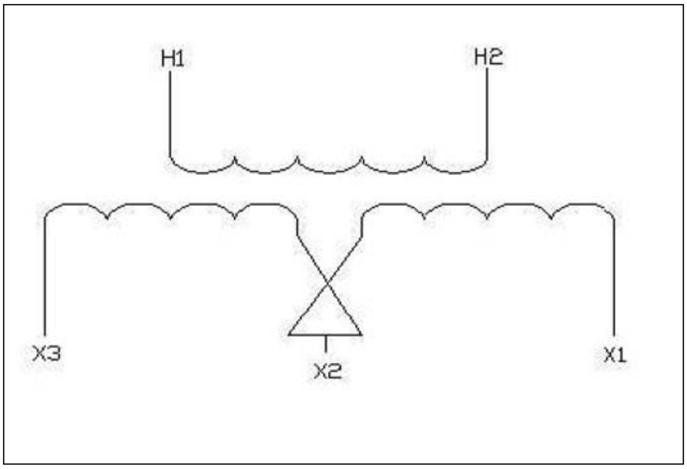

Figure 7: Single-Phase Transformer Connection

### MOTOR CIRCUIT ANALYSIS BASICS

Motor Circuit Analysis is the art of troubleshooting and pinpointing faults within an inductive or capacitive circuit by using readings of resistance, impedance, inductance, phase angle, insulation resistance and I/F.

The ALL-TEST™ static MCA instrument puts out a low voltage, 100 to 800 Hz signal, as a true sine wave which it then evaluates the response using a series of bridges. These readings relate as follow:

1. Resistance (Ohms): The simple DC resistance of the circuit.

2. Inductance (Henries): The magnetic strength of a coil.

3. Capacitance (Farads): Measurement of leakage.

4. Inductive Reactance ($X_L$): The AC resistance of a coil. $X_L = 2\pi fL$

5. Capacitive Reactance ($X_C$): $X_C = 1/(2\pi fC)$

6. Phase Angle (Fi, degrees): The angle of the lag of current to voltage.

7. Impedance (Z): The complex resistance of an AC circuit.

$$Z = \sqrt{R^2 + (X_L - X_C)^2}$$

8. Current/Frequency Response (I/F): Percentage change in current when the frequency is doubled by the instrument, as $I = V / Z$.

9. Insulation Resistance (Meg-Ohms): Measurement of leakage to ground, ground-wall insulation strength.

When taken as a group, these readings can assist the analyst in determining, first, if a fault exists, then the type of fault. Using the ALL-TEST IV Pro™ 2000, these readings can be taken in less than 5 minutes per transformer. The key to MCA testing is to compare readings between similar windings or transformers and to look at the variations and patterns between phases.

Figure 8: Motor Circuit Analysis Instrument

### TRANSFORMER FIELD TEST

The initial set of tests were performed using the same type of procedure that would be used on an electric motor, first for the primary windings, then for the secondary windings. Table 1 represents a sample of one of 30 transformers that were tested over a period of 90 minutes.

An issue that became immediately apparent was the unusual and extremely unbalanced readings. All of the tests identified similar results and it was also noticed that resistance varied from test to test and that the impedance and inductance changed from test to test. Upon evaluation of these phenomena, two theories were developed:

1. The sinusoidal voltage output of the ALL-TEST was inducing into the opposite set of windings resulting in reflected impedance and inductances that would increase during each test because of a resulting static charge.

2. Electro-Magnetic Interference (EMI) from surrounding operating equipment, transformers, lighting, etc. would cause stray currents because the transformer windings and core would act as an excellent EMI antennae. This scenario would explain varying resistances from test to test.

To resolve both issues, the connections on the side opposite of the side being tested should be grounded to a proper earth ground. The result was predicted to shunt all induced currents direct to ground resulting in the ability to fully test just the winding being tested. This would also allow for tighter testing tolerances. The results are found in Table 2 and test time remained under 5 minutes per transformer.

These results were found to be repeatable in all cases. Transformers that tested bad tended to have drastic variations

| | Primary | | | Secondary | | |
|---|---|---|---|---|---|---|
| | H1-H2 | H1-H3 | H2-H3 | X1-X2 | X1-X3 | X2-X3 |
| Resistance | 258.5 | 48.45 | 153.3 | 0.198 | 0.125 | 0.132 |
| Impedance | 15633 | 11028 | 11035 | 566 | 411 | 420 |
| Inductance | 24878 | 17552 | 17562 | 902 | 655 | 669 |
| I/F | -50 | -23 | -18 | -44 | -46 | -44 |
| Phase Angle | 9 | 90 | 90 | 90 | 85 | 90 |
| Meg-Ohm | >99 | | | >99 | | |

**Table 1: Initial Transformer Test Data: 2500 kVA Transformer**

| | Primary | | | Secondary | | |
|---|---|---|---|---|---|---|
| | H1-H2 | H1-H3 | H2-H3 | X1-X2 | X1-X3 | X2-X3 |
| Resistance | 3.703 | 3.623 | 3.648 | 0.103 | 0.100 | 0.096 |
| Impedance | 220 | 217 | 218 | 15 | 14 | 14 |
| Inductance | 87 | 86 | 86 | 2 | 2 | 2 |
| I/F | -49 | -49 | -49 | -48 | -48 | -49 |
| Phase Angle | 88 | 88 | 88 | 75 | 75 | 75 |
| Meg-Ohm | >99 | | | >99 | | |

**Table 2: Final Transformer Test Data: 2500 kVA Transformer**

| | Primary | | | Secondary | | |
|---|---|---|---|---|---|---|
| | H1-H2 | H1-H3 | H2-H3 | X1-X2 | X1-X3 | X2-X3 |
| Resistance | 116.1 | 98.2 | 48.5 | 0 | 0.005 | 0.005 |
| Impedance | 4972 | 1427 | 2237 | 0 | 1 | 1 |
| Inductance | 7911 | 2267 | 2237 | 0 | 0 | 0 |
| I/F | -33 | -29 | -29 | 0 | -20 | -20 |
| Phase Angle | 23 | 21 | 20 | 0 | 5 | 5 |
| Meg-Ohm | 9.132 | | | 0 | | |

**Table 3: Shorted Transformer**

in readings.

It was found that the 500 kVA transformer had a shorted primary with damage between the primary and secondary windings.

## TRANSFORMER TESTING PROCEDURE

The results of the study produced simple test procedures for both three-phase pad and single-phase pole mounted transformers. The key to testing any type of transformer is to ground all of the leads on all of the connections of the winding opposite of the winding being tested.

A good transformer should have unbalances less than:

1. Resistance: No more than 5% unbalance above 0.250 Ohms and 7.5% below 0.250 Ohms.
2. Impedance: < 2% unbalance
3. Inductance: < 5% unbalance
4. Phase Angle: No more than 1 degree between phases

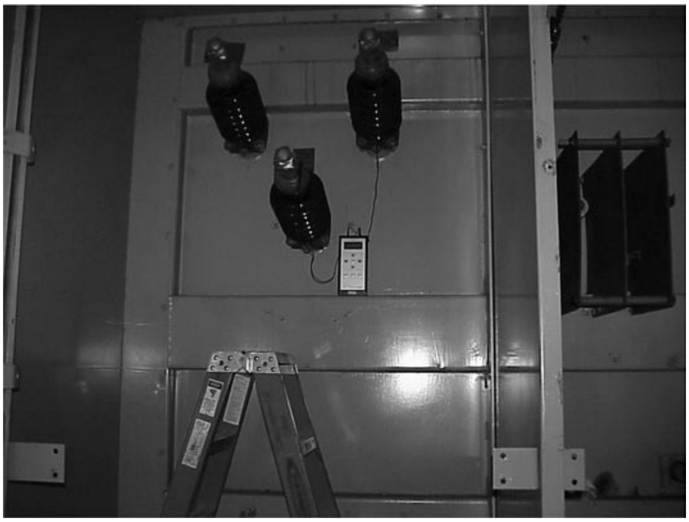

**Figure 9: Transformer Test**

5. I/F: No more than 2 digits difference and the readings should fall between œ 15 and œ 50.

6. A "shift" in readings should be flagged for further testing or trending. For instance, a winding that tests as I/F: -48; -48; -46 and Phase Angle: 70°; 70°; 69°, should be checked further.

Normally, a winding is beginning to experience inter-turn shorts when the Phase Angle and I/F begin to shift. A corresponding unbalance in inductance and impedance indicates a severe fault. A change in Phase Angle with a fairly balanced I/F normally indicates a phase short.

The basic steps for three-phase transformer testing are as follows:

1. All of the leads on the side opposite of the side being tested must be grounded to an earth ground.

2. Test the primary from H1 to H2, then "retest" to verify that the readings are repeatable. If they are not repeatable, check the ground and continue.

3. Test from H1 to H3, then H2 to H3, and, finally a ground insulation test.

4. Save the readings and check condition.

5. Test the secondary winding by first checking X1 to X2, then "retest" to verify that the readings are repeatable.
If they are not repeatable, check the ground and continue.

6. Test from X1 to X3, then X2 to X3, and, finally, a ground insulation test.

7. Save the readings and check condition.

Single-phase transformers are tested slightly differently and require a known reading for the primary to be compared to, such as with a similar transformer or a past test on the same transformer. The basic steps for single phase transformer testing are as follow:

1. All of the leads on the side opposite of the side being tested must be grounded to an earth ground.

2. Test the primary from H1 to H2, then "retest" to verify that the readings are repeatable. If they are not repeatable, check the ground and retest

3. Ground the primary then test X1 to X2, then "retest" to verify that the readings are repeatable. If they are not, then check the ground and retest.

4. Test from X2 to X3, then save readings. Compare the second and third reading to each other and the first reading to a standard.

These procedures can be used on three phase pad mount and single phase pole mount transformers regardless of connection type.

## CONCLUSION

Static Motor Circuit Analysis techniques provide an excellent method for analyzing the primary and secondary windings of either three-phase pad and single-phase pole mounted transformers. A simple procedure incorporating grounding the side opposite of the side being tested allow for very accurate test results. Measurements of resistance, impedance, inductance, phase angle, current response and insulation resistance can be compared for troubleshooting purposes and measurement patterns for pinpointing faults.

Test equipment required for MCA testing transformers must have the following capabilities:

1. Resistance, impedance, inductance, phase angle, I/F and insulation resistance in engineering units.

2. Sine-wave voltage output in a variety of frequencies.

3. Onboard memory with software to upload and download readings.

4. Cost effective and accurate.

The procedures described require about five minutes per transformer with a greater than 99% test result accuracy.

## *ABOUT THE AUTHOR*

*Dr. Howard W. Penrose, Ph.D. has over 15 years in the electric motor and electric motor repair industry. Starting as an electric motor repair journeyman in the US Navy to field service and evaluation of small through large rotating equipment of all types, as the Chief Engineer of a large Midwestern motor repair shop. Dr. Penrose has been directly involved in rewinding, training and troubleshooting AC, DC, wound rotor, synchronous, machine tool, and specialty equipment. His further studies involve electric motor and industrial reliability, test methods, energy efficiency and maintenance impact on production. Dr. Penrose is a past Chair of the Chicago Section of IEEE, a past Chair of Dielectrics and Electrical Insulation Society of IEEE Chicago, a Professional Member of the Electrical Manufacturing Coil and Winding Association, a US Department of Energy Certified MotorMaster Professional, a Vibration Analyst, Infrared Analyst and Motor Circuit Analyst.*

# New Measurement Methods to Characterize Transformer Core Loss and Copper Loss in High Frequency Switching Mode Power Supplies

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## I. INTRODUCTION

Measurement methods are widely used for transformer core loss and copper loss characterization due to the potential for higher accuracy in comparison to simple conventional analytical methods. Unfortunately, no measurement methods are available that can measure the transformer core loss and copper loss under the actual operation conditions in switching mode power supplies (SMPS).

The existing measurement methods determine transformer core loss under sinusoidal excitation using an impedance or network analyzer [1],[2]. However, the pulse width modulation (PWM) waveforms in SMPS are not sinusoidal, but are rectangular. In addition, converters such as the flyback and asymmetrical half-bridge (AHB) contain a DC bias in the magnetizing current, but these methods cannot account for the DC bias. Furthermore, due to the highly non-linear nature of the B-H property of ferrite materials, Fourier analysis can yield completely erroneous results. Therefore, the impedance or network analyzer method cannot be applied to accurately determine the core loss in high frequency switching converters.

In [3] and [4], two measurement setups were designed to experimentally determine transformer core loss. In [3], sine waveforms were used to obtain the core loss curves for the ferrite materials. In addition, no core loss results for switching converters are provided. In [4], a method is proposed to measure transformer core loss for a SMPS using a waveform generator and a power amplifier.

Unfortunately, using these techniques, the core loss cannot be determined if the transformer under test operates with a DC bias in the magnetizing current. It is also noted that an error analysis of the proposed methods was not conducted and the corresponding measurement accuracy was not provided. Therefore, if these techniques are used, the user cannot interpret the accuracy of their results. To overcome the limitations of the existing methods, an improved method to determine transformer core loss in high frequency SMPS is proposed, which is suitable for core loss measurement under PWM excitation, with or without a DC bias.

In [5], a method is proposed to calculate transformer copper loss by measuring winding AC resistance for each harmonic in the PWM current. The method uses sinusoidal waveforms in the measurement and not the rectangular PWM waveforms under the transformer operating conditions. The drawback to this technique is that it does not replicate the field pattern within the transformer. In addition, the measurements are time-consuming. Another disadvantage of this method is that the results only provide information about winding self-resistance. When both the primary and secondary windings have current flowing through them at the same time, the field interaction due to proximity effect induces a mutual resistance between them, which can significantly reduce the total transformer copper loss. Therefore, an "in-component" measurement scheme for transformer AC winding resistance is proposed. The method uses the PWM current waveforms, so, the mutual resistance between windings is inherently included, which yields increased accuracy.

In section II, the core loss measurement method is proposed. In section III, the proposed copper loss measurement method is presented. The experimental verification is provided in section IV. In section V, a detailed error analysis is presented for each method. The conclusions are presented in section VI.

## II. PROPOSED CORE LOSS MEASUREMENT METHOD

The proposed transformer core loss measurement test setup is shown in Figure 1. With the secondary side open circuit, the averaged core loss PCore over one switching period T can be determined from the primary voltage vpri(t) and the magnetizing current iM(t) using (1).

$$P_{Core} = \frac{1}{T}\int_0^T v_{pri}(t)\cdot i_M(t)\,dt \qquad (1)$$

Due to the leakage inductance and resistance associated with the primary winding, the winding voltage cannot be measured directly. However, the secondary side voltage vsec(t) can be measured and reflected back to the primary side using the turns ratio. Since the secondary winding is open circuit, the only primary terminal current is the magnetizing current, which is sensed using a resistor RSense.

By measuring the secondary voltage and the voltage across a sensing resistor, we can obtain the averaged core loss over one switching period T using (2).

Using a digital oscilloscope with channel math capabilities, (2) can be evaluated directly using the oscilloscope. In (2), NP and Ns are the primary and secondary winding turns; v1i and v2i are the ith sample of the measured voltage values of the secondary side and current sensing resistor; N is the number of the samples in one switching period.

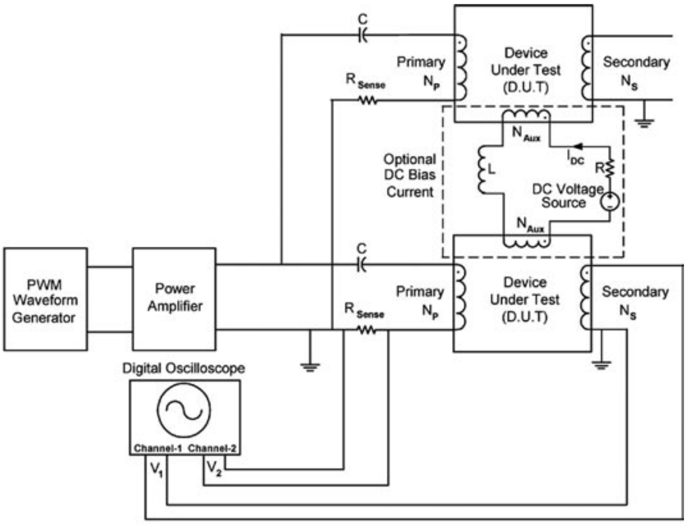


Figure 1 Proposed core loss measurement test setup

$$P_{Core} = \frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}\cdot\frac{v_{2i}}{R_{sense}} \qquad (2)$$

The practical implementation issues of the measurement setup are explained as follows:

### 1) POWER SOURCE

A PWM waveform generator (function generator) and an RF power amplifier (3MHz bandwidth) are used to provide the PWM voltage source to the transformer.

### 2) CURRENT SENSING DEVICE

A low-inductive metal film resistor is used to measure the magnetizing current. In order to minimize the distortion on the waveform and at the same time to reduce the phaseshift error, ten 10Ω±1% metal film resistors were connected in parallel. The impedance characteristic of the resistor combination is flat up to 5MHz.

### 3) DC BIAS CURRENT

An optional auxiliary winding can be introduced to provide the equivalent DC magnetomotive force to the core for transformers that operate with a DC bias component in the magnetizing current. A 2mH inductor was connected in the auxiliary circuit to reduce the high frequency AC ripple.

In addition, two auxiliary windings with the same number of turns were connected with opposite polarities to eliminate the AC voltage from the primary winding. The second auxiliary winding is connected into the same transformer as the one under test.

In order to ensure the measurement of the transformer core loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

### A. CALIBRATION OF THE WINDING TURNS RATIO

The proposed core loss measurement method has two ports.

Due to the non-ideal magnetic coupling, parasitic air flux and the winding terminations, the primary and secondary winding terminal voltage ratio can vary slightly from the designed turns ratio. In order to minimize this error, the winding turns ratio should be calibrated. For the turns ratio calibration, a sinusoidal wave can be used to simplify the process. The turns ratio result can be applied to the rectangular PWM waveforms under test. The terminal voltages (peak or peak-to-peak value) of the primary and secondary windings are measured and the actual turns ratio is calculated using (3), which is then used in (2). The calibration should be conducted over a range of frequencies.

$$N_{Turns-Ratio} = V_{\Pr i} / V_{Sec} \tag{3}$$

## B. CURRENT SENSING RESISTANCE CALIBRATION

Some error will be introduced into the core loss measurement due to the tolerance and the associated inductance of the current sense resistor. A good approach is to calibrate the resistor's frequency response using the impedance analyzer to ensure its frequency response remains flat for several harmonics of the switching frequency.

## C. AVERAGING DATA

Averaging should be adopted for the data processing.
The core loss for each operating condition should be tested ten times and then the values should be averaged.

## III. PROPOSED COPPER LOSS MEASUREMENT METHOD

The objective of transformer copper loss measurement is to obtain an equivalent AC resistance for each winding under the actual operating conditions. To proceed, it is important to clarify the following two concepts:

1) We need to define the current wave shape used in the measurement under the SMPS operating conditions. By analyzing the SMPS circuits, the currents flowing through the windings can usually be well approximated as a rectangular wave shape (unipolar or bipolar) of the corresponding duty ratio by neglecting the small ripple [6].

Therefore, a rectangular PWM current can be used in measuring the transformer copper loss. In this article, a bipolar rectangular PWM waveform is used.

2) A transformer is a multi-winding structure, so, the field interaction between the primary and secondary windings induces a mutual resistance. Fortunately, we don't need to obtain the mutual resistance information. What we need is an equivalent AC resistance of each winding under the operating condition, which includes the mutual resistance information.

The proposed transformer winding AC resistance measurement scheme is shown in Figure 2. By applying the rectangular PWM voltage in the primary side from the waveform generator and power amplifier, the corresponding magnetic field is established within the transformer and a PWM voltage is induced in the secondary side. If a resistive load is connected on the secondary side, a rectangular current will flow through the load resistor and the secondary winding equivalent AC resistance. The secondary side current iSec can be obtained by measuring the voltage across the load resistor. An auxiliary winding is added to measure the secondary winding terminal voltage. This winding can be easily added externally around the core since it does not carry any current. The two voltages are then measured using a digital oscilloscope. Then the averaged power of the secondary winding PSec and the power of the load resistor PLoad can be calculated over one switching period.

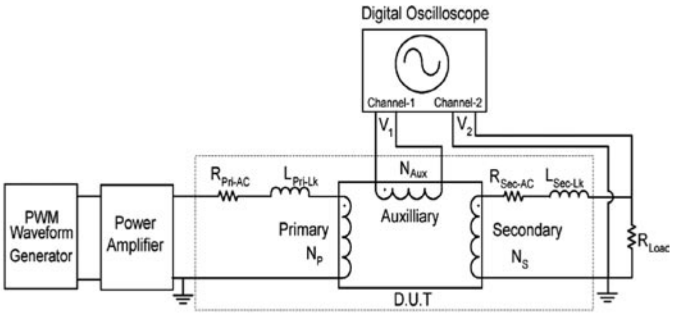


Figure 2 Proposed copper loss measurement test setup

$$R_{Sec-AC} = \frac{P_{Sec} - P_{Load}}{I^2_{SecRMS}} = \frac{\frac{N_{Sec}}{N_{Aux}} \frac{1}{N} \sum_{i=1}^{N} v_{1i} \cdot \frac{v_{2i}}{R_{Load}}}{\frac{1}{N} \sum_{i=1}^{N} \left( \frac{v_{2i}}{R_{Load}} \right)^2} - R_{Load} \tag{4}$$

Therefore, the secondary winding equivalent AC resistance can then be calculated using (4), where NSec and NAux are the secondary and auxiliary winding turns; v1i and v2i are the ith sample of the voltage values; and N is the number of the samples in one switching period.

By defining the corresponding functions in the digital oscilloscope, the power of the measured winding and the RMS current value over one switching period can be obtained easily and used in the winding resistance calculation. In order to measure the primary winding AC resistance, the secondary winding should be excited.

In order to ensure the measurement of the transformer copper loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

## A. CALIBRATION OF THE WINDING TURNS RATIO

In the proposed transformer winding AC resistance measurement method, a third winding is used to obtain the terminal voltage of the measured winding. The actual winding turns ratio between the measured winding and the third winding should be calibrated in order to achieve accurate results. This can be achieved using the procedure outlined in section II.

### A. Load Resistance Calibration

Since a resistor is used as the load in measuring the winding AC resistance, the resistor's tolerance and frequency response can have a significant impact on measurement results. In order to minimize any error introduced by the resistor, the resistor's frequency response should be measured using an impedance analyzer to obtain an accurate resistance value and phase response.

### B. Averaging Data

As in the core loss calculation, the copper loss data in the winding AC resistance measurement should be averaged in order to minimize any random error in the measurements.

## IV. MEASUREMENT RESULTS AND VERIFICATION

A high frequency planar transformer was tested to verify the proposed core loss and copper loss methods. In order to verify the loss measurement results, a time-domain Finite Element Analysis solver from ANSOFT was used.

A multi-winding planar transformer was used in an AHB DC/DC converter with unbalanced secondary windings [7].

The converter diagram is shown in Figure 3. The specifications of the converter and the transformer parameters are:

Input: 35-75V, nominal at 48V, output: 5V/25W
Switching frequency: 400kHz
Main winding turns: Np: Ns1: Ns2 = 6:1:3
Core: E18/4/10 planar cores (EE combination)
Winding: 1oz (35micrometres) copper on a 10-layer PCB

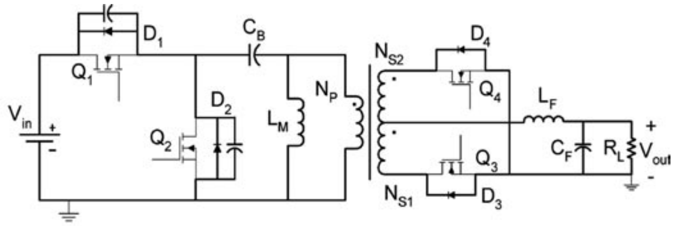


**Figure 3 AHB converter diagram**

Due to the complementary duty cycle operation and unbalanced secondary windings, the converter operates with a DC bias (IM-DC) in the magnetizing current. It can be calculated using (5).

$$I_{M-DC} = (1-D)I_o\frac{N_{s2}}{N_p} - DI_o\frac{N_{s1}}{N_p} \qquad (5)$$

In the transformer design, an air gap of 67 micrometres was added to the core central leg to avoid saturation. The proposed optional circuit to create the DC bias current for the test setup was used in the core loss measurement.

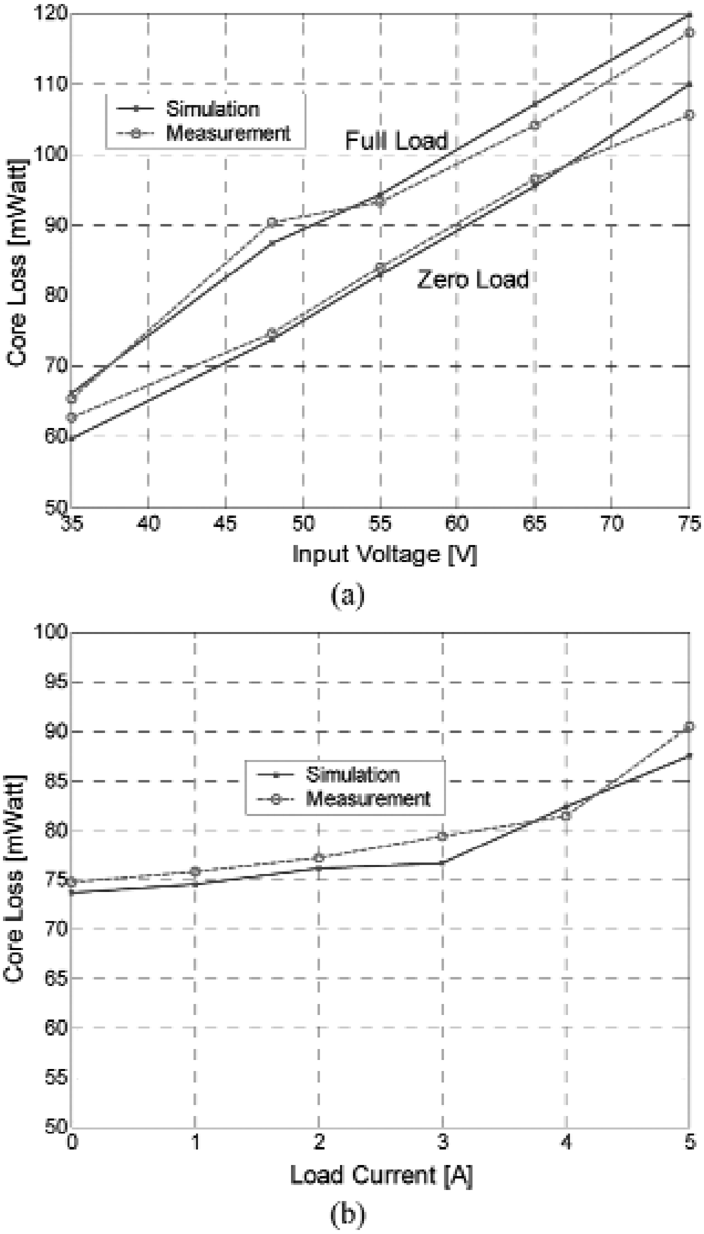
### A. Core Loss Measurement Results

The following three operating conditions of the AHB transformer were tested using the proposed method.

1) Vin=35-75V range @ no load
2) Vin=35-75V range @ 5A load
3) Vin=48V @ 0-5A load range

The measurement results and FEA simulation results are provided in Figure 4. In order to illustrate the effect of the DC bias current on the ferrite core loss, Figure 4(a) shows the core loss measurement and simulation results under operating conditions (1) and (2). Figure 4(b) provides the results for operating condition 3). The core losses under the equivalent 400kHz sine waveform and bipolar square waveform (D=50%) with no DC bias current condition were also tested for comparison purposes.

Some typical core loss measurement waveforms under operating condition 1 are shown in Figure 5. The digital oscilloscope math functions implement (2). The results are indicated on the right side of the figure.



(a)

(b)

**Figure 4 AHB transformer core loss results**

It is clear from the test results that the core loss under PWM waveform excitation increases as the duty ratio decreases and that the addition of a DC bias current increases core loss.

Using the FEA simulation result as the reference, the difference between the measurement and the FEA simulation is within plus or minus 5% for all the measurement conditions.

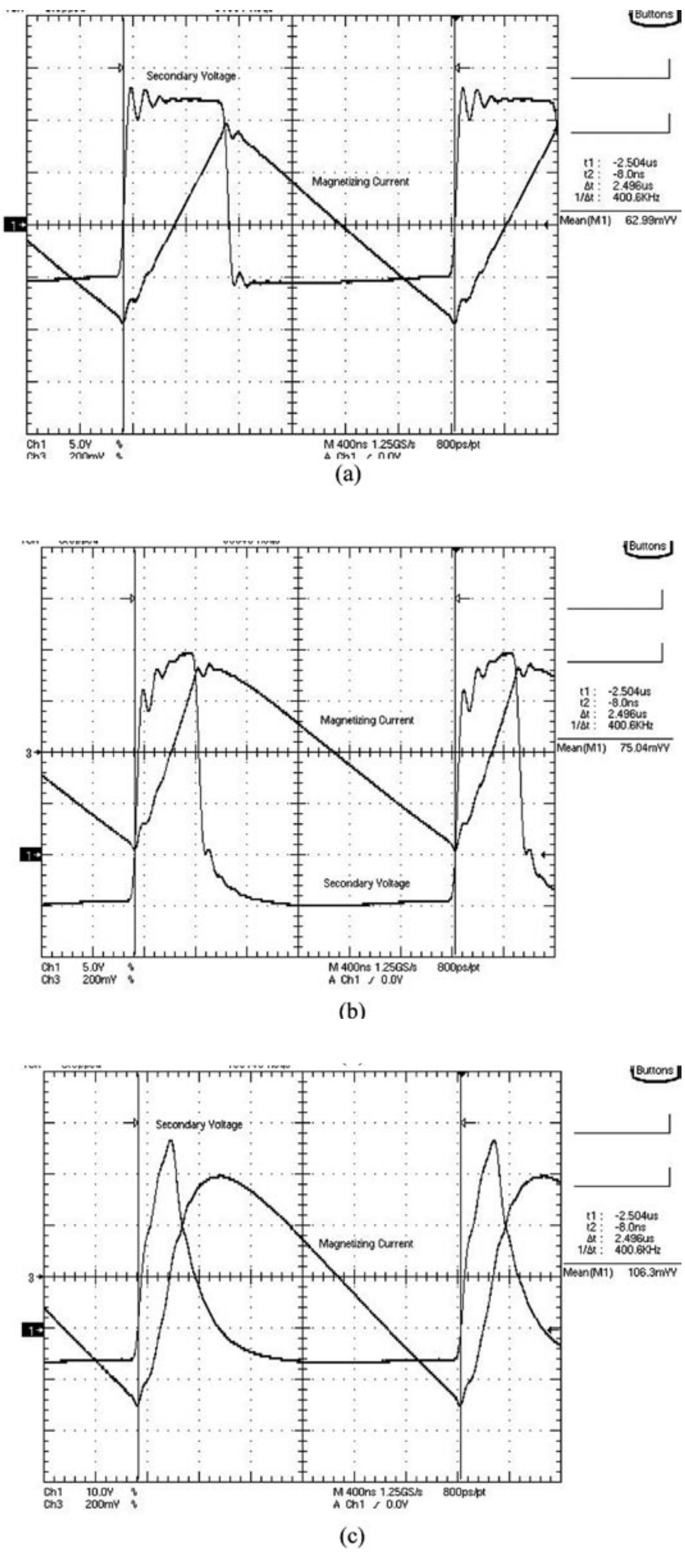


Figure 5 AHB core loss measurement waveforms: (a) Vin=35V, (b) Vin=48V, (c) Vin=75V

### A. Winding AC Resistance Measurement Results

The AC resistance of the AHB transformer power windings were measured and 3D FEA simulations were conducted to compare the results. The measurement and FEA simulation results are illustrated in Figure 6. The DC resistances are also provided as a reference.

Using the simulation results as reference, the difference between the measurement and FEA simulation results are within plus or minus 10% for the three AHB transformer powertrain windings. The measurement waveforms are shown for the secondary-I winding in Figure 7.

We can observe from the test results that the winding equivalent AC resistance under PWM waveform excitation is larger than that under sinusoidal excitation. In addition, the resistance increases as the duty ratio decreases.

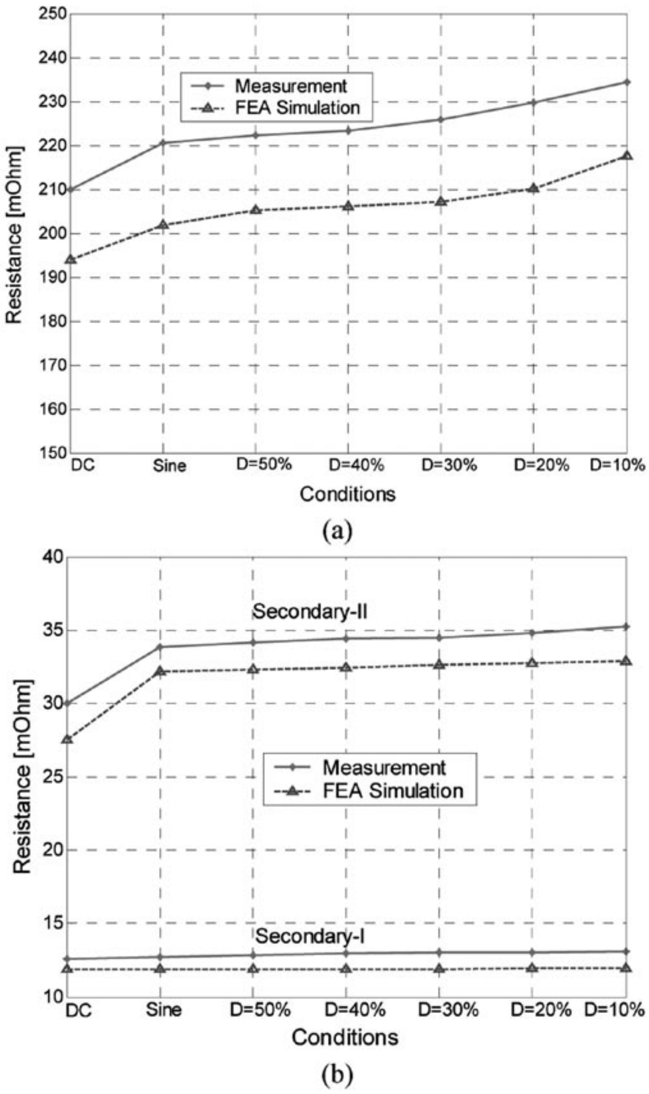


Figure 6 AHB transformer winding AC resistance; (a) primary winding, and (b) secondary windings

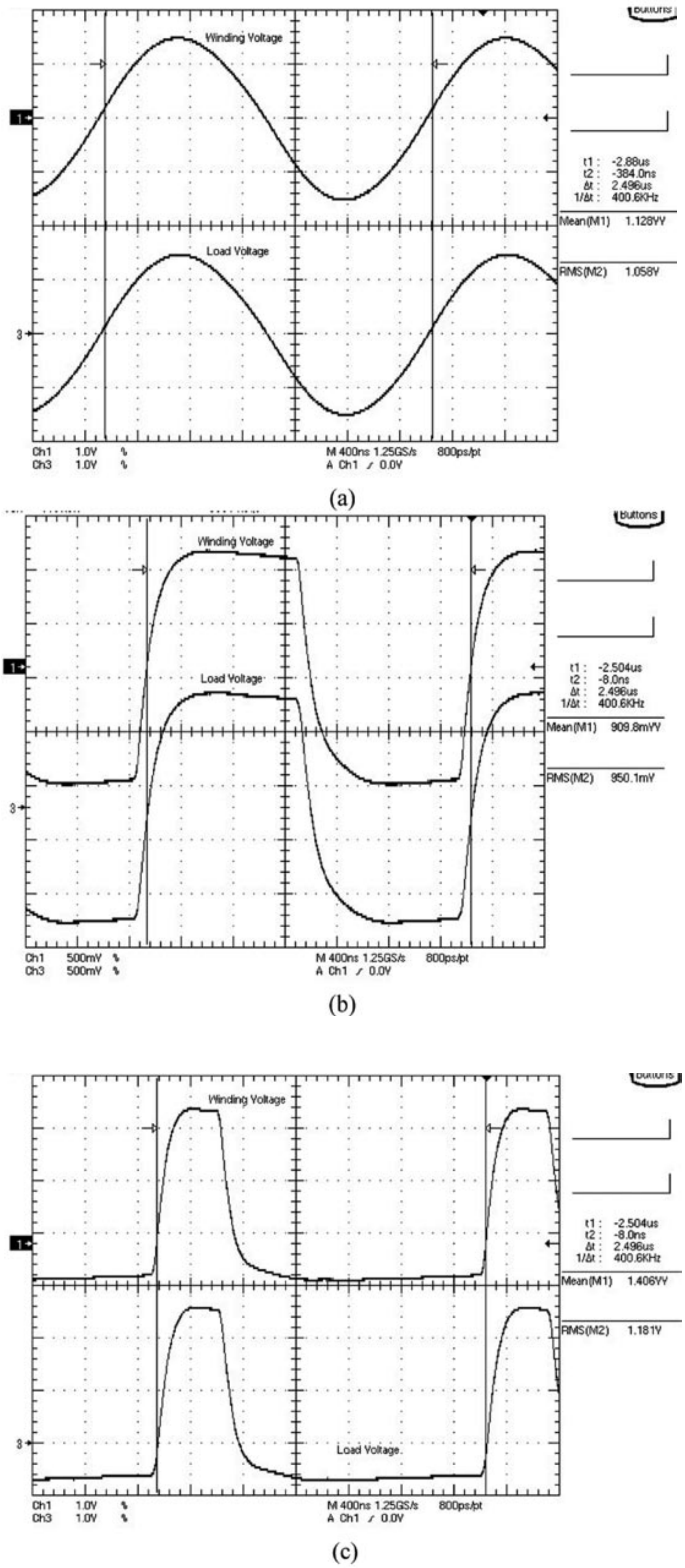


**Figure 7 AHB transformer secondary-I winding AC resistance measurement waveforms; (a) sinusoidal, (b) D=50%, and (c) D=20%**

## V. ERROR ANALYSIS

In order to ensure that the core loss and winding AC resistance measurements are accurate and valid, it is necessary to analyze the various error sources in the measurements to obtain the loss measurement accuracy.

### A. ERROR ANALYSIS FOR CORE LOSS MEASUREMENT

Using (2), the core loss is determined using the winding voltage and magnetizing current. Therefore, the error analysis of the proposed core loss measurement method is based on (2). The various error sources and their effect on the core loss measurement accuracy are analyzed as follows.

#### 1) VOLTAGE MEASUREMENT ERROR

The Tektronix TDS5054 digital oscilloscope was used for the tests. It has an 8-bit ADC. The averaging acquisition mode was used in the measurement, so, the effective sampling resolution can be as high as 11-bit. Both the digitizing and the linearity errors in the measurement are ±1/2LSB at full scale. Combining these factors, we can assume that the voltage measurement error is ±1LSB at full scale.

For the measurements, the location of the peak value of the voltage waveform measured on the oscilloscope determines the voltage measurement error. In the measurement, the peak value is always kept above 10% of the full scale (for the worst case). For the vertical scale, the voltage measurement error of the oscilloscope is less than 0.489%. Therefore, from (2), the relative error of the worst case core loss due to the voltage measurement is given by (6), which is less than 1% for the given test setup.

$$\frac{\Delta P_{Core}}{P_{Core}} = \left| \frac{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}(1\pm 0.489\%)\cdot\frac{v_{2i}(1\pm 0.489\%)}{R_{sense}}}{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}\cdot\frac{v_{2i}}{R_{sense}}} - 1 \right| = 0.98\% \qquad (6)$$

#### 2) TURNS RATIO ERROR

As explained in section II, calibration of the turns ratio between the primary and secondary windings helps to minimize error. In the turns ratio calibration procedure, (3) is used for the calculation. The peak voltage is kept close to the full scale of the oscilloscope, so, the digitizing error in the voltage measurement for the turns ratio calibration can be considered as ±1LSB of the ADC, which is 2-11.

Therefore, based on (3), the worst-case relative error for the turns ratio calibration is less than 0.1%.

In this article, the digitizing error is neglected, so, we can assume that no error is introduced into the calibration procedure of the turns ratio. Using this calibration method, the turns ratio between the primary and secondary-II winding in the AHB transformer is 2.04 from 400kHz to 2MHz. Without this turns ratio calibration, a relative error of 2% will be introduced into the core loss measurement results.

#### 3) TOLERANCE OF THE CURRENT SENSING RESISTOR

The metal film resistor used in the core loss measurement has

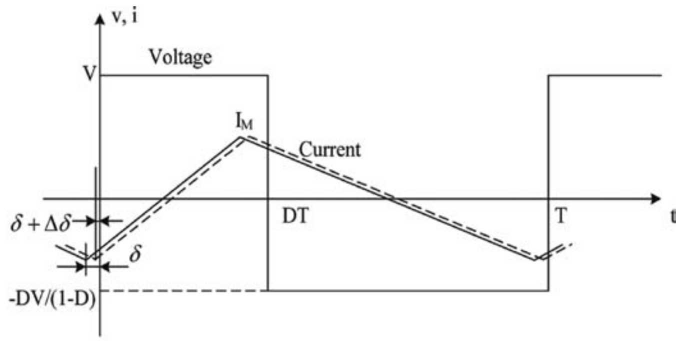


**Figure 8 Ideal and typical transformer voltage and magnetizing current**

a tolerance of plus or minus 1%. Therefore, a 1% relative error is introduced due to the current sensing resistor.

### 4) TIME DELAY ERROR

Another important error source is time delay error due to the inductance of the current sensing resistor. For SMPS transformers, ideally, the voltage and current waveforms are in the wave shapes as shown in Figure 8 by the solid lines.

The time delay between the voltage and the magnetizing current can be defined as d. Then, from (1), (7) can be derived. In (7), V is the amplitude of the positive part of voltage waveform; IM is the amplitude of the magnetizing current; D is the duty ratio of the PWM waveform; T is the switching period of the circuit; and d is the time delay between the voltage and the magnetizing current.

$$P_{Core} = V \cdot I_M \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \tag{7}$$

Since the magnetizing current is sensed by a resistor, (7) can be written as (8).

$$P_{Core} = V \cdot \frac{V_R}{R_{Sense}} \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \tag{8}$$

If some error, Delta d is introduced into the time delay, d the magnetizing current waveform will be shifted with respect to the actual waveform as illustrated by the dashed line in Figure 8. Then the incremental core loss due to this error can be calculated using (9).

$$\Delta P_{Core} = \frac{\partial P_{Core}}{\partial \delta} \Delta\delta \tag{9}$$

Using (8) and (9), the relative error of the core loss power due to Delta d is given by (10).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| = \left|\frac{2DT - 2D^2 T - 2\delta}{2D\delta T - 2D^2\delta T - \delta^2}\right| \left|\Delta\delta\right| \tag{10}$$

When d <<DT and D<<D2T, (10) can be approximated by (11).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| \approx \left|\frac{\Delta\delta}{\delta}\right| \tag{11}$$

It is clear that the relative error is very sensitive to small values of d. In this case, if large time delay error is introduced, the relative error will become large. Therefore, care should be taken to minimize time delay error.

Sources of time delay error can be: poor frequency response of the current-sensing device; and trigger jitter and delays for different channels introduced by the oscilloscope.

For the digital oscilloscope used, the trigger jitter is typical at 8 ps, so, it can be ignored. The probes used for the voltage measurement are originally from the same oscilloscope and are matched to each other, so, the phase delay between channels of the oscilloscope can be neglected. The inductance associated with the current sensing resistor is the important source of the phase delay error. Therefore, in experiments, care should be taken to reduce these error sources and small inductance metal film resistor is used.

Using an impedance analyzer, phase shift less than 0.01 degree is observed for the current sensing resistor at 400kHz. It is less than 0.02 degrees at 800kHz and 0.05 degrees at 2MHz. Using the phase shift at 400kHz and transferring it to delay time for 400kHz, the time error can be calculated as given by (12).

$$\Delta\delta = \frac{0.01^\circ}{360^\circ} \times 2.5\mu s = 69.5ps \tag{12}$$

The relative error depends on the time delay and the error introduced due to the time delay, so the value changes for different operating conditions. For example, the time delay between the voltage and magnetizing current can be calculated as d=59ns using (8) for the AHB transformer operating at 48V input. With a time delay error of Delta d=69.5ps introduced by the current sensing resistor, we can obtain the relative core loss error as less than 0.12% using (10). This calculation procedure can be applied for other operating conditions and a relative error of less than 0.2% is obtained for all the operating conditions.

B. ERROR ANALYSIS FOR COPPER LOSS MEASUREMENT

The main error sources in the winding resistance measurement are: (1) voltage measurement error, (2) turns ratio error, (3) tolerance of the load resistor, (4) time delay introduce into the load current measurement.

By manipulating (4), (13) can be derived.

$$R_{Sec-AC} = R_{Load} \cdot \left( \frac{\frac{N_{Sec}}{N_{Aux}} \cdot \sum_{i=1}^{N} v_{1i} \cdot v_{2i}}{\sum_{i=1}^{N} (v_{2i})^2} - 1 \right) \tag{13}$$

The effect of each error source on the winding AC resistance measurement is analyzed as follows.

### 1) VOLTAGE MEASUREMENT ERROR

The TDS5054 uses one ADC for all four channels. Therefore, the digitizing errors of the voltage measurement for each channel can be considered equal. Furthermore, the digitizing error will cancel out in the numerator and denominator in the first item in (13), so we can assume that the digitizing error can be neglected.

### 2) TURNS RATIO ERROR

An auxiliary winding is used to obtain the winding voltage. Since a calibration of the turns ratio is carried out to obtain the actual turns ratio, this error can be ignored.

### 3) TOLERANCE OF THE LOAD RESISTOR

The load resistor used in the measurement has a tolerance of plus or minus 1%, so a relative error of 1% is introduced into the winding AC resistance measurement.

### 4) TIME DELAY ERROR

In the load current measurement, a pure resistor value is assumed as the load. However, the inductance of the resistor and the inductance induced in the measurement circuit will introduce some time shift error for the current.

For a SMPS with a rectangular PWM voltage and current waveform as shown in Figure 9 (the leakage inductance can be neglected because it is very small), the winding AC resistance can be calculated using (14), where, V1 is the positive amplitude of the auxiliary winding voltage; V2 is the positive amplitude of the load resistor voltage; and NTurn-Ratio is the actual turns ratio between the auxiliary and the measured windings after calibration.

$$R_{Sec-AC} = R_{Load} \cdot (N_{Turn-Ratio} \cdot \frac{V_1}{V_2} - 1) \qquad (14)$$

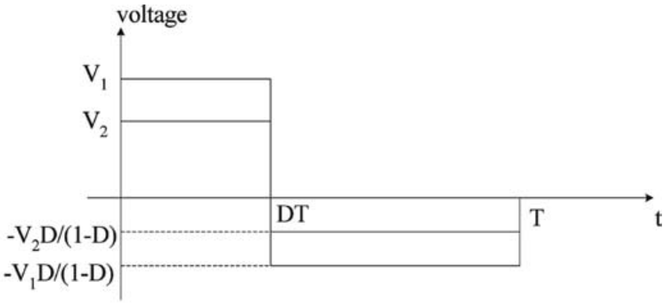


**Figure 9 Typical and ideal PWM voltage and current waveform in measuring winding AC resistance**

Due to the parasitic inductance, some time delay will be introduced into the load current measurement as shown in Figure 10. With this time delay, the winding AC resistance is given by (15).

$$R_{Sec-AC} = R_{Load}\left[N_{Turn-Ratio} \cdot \frac{V_1}{V_2}\left(1-\frac{\delta}{D(1-D)T}\right)-1\right] \qquad (15)$$

Then, the relative error due to the time delay can be calculated using (16).

$$\frac{\Delta R_{Sec-AC}}{R_{Sec-AC}} = \frac{\dfrac{\delta}{D(1-D)T}}{1-\dfrac{V_2}{N \cdot V_1}} \qquad (16)$$

If the load resistor is much larger than the winding AC resistance, then the ratio of V2/V1 in (16) will be very close to one. In this case, the relative error will be very sensitive to the time delay and care should be taken to minimize the parasitic inductance in the measurement.

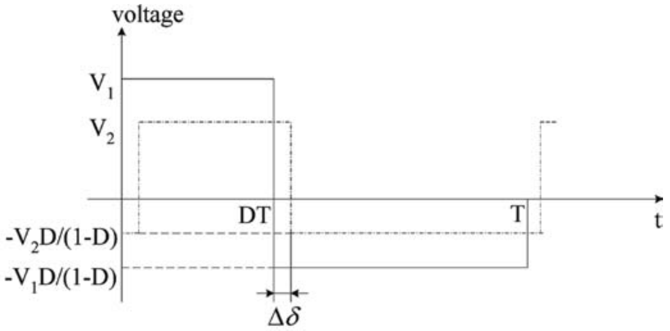


**Figure 10 Time delay introduced into the load current measurement**

## VI. CONCLUSIONS

New measurement schemes to characterize transformer core loss and copper loss for SMPS were proposed.

Measurement results were presented for a planar transformer operating in a DC/DC power converter. FEA simulation using a time-domain solver was used to verify the measurement results. In addition, a detailed error analysis has been provided for the proposed core loss and copper loss measurement methods. The results show that the proposed methods can provide accurate measurement of transformer core loss and copper loss for high frequency SMPS.

Using the error analysis results, the relative error was calculated to be less than 5% for all the measurement conditions for the AHB transformer core loss; For the winding AC resistance, the measurement accuracy is: <2% for the primary winding, <5% for the secondary-I winding and <4% for the secondary-II winding.

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# Infrared Diagnostics On Padmount Transformer Elbows

**Jeff Sullivan, Mississippi Power Company, Hattiesburg, MS**

## ABSTRACT

Mississippi Power Company has been a leader and trend-setter in finding new and better ways to increase customer satisfaction. For this reason, we implemented a program of infrared thermographic inspection using infrared thermal imaging cameras, on all the electrical equipment in our facilities, including all of our 750 KVA to 2500 KVA padmount transformers, one of which had failed disastrously.

During a survey of these transformers, I detected thermal problems with more than 30% of the 400 scanned, all associated with the high side elbow connection. Further investigation related the failure mechanisms to improper installation techniques during both the original installation and the routine preventive-maintenance replacement of the elbows.

Using newer improved equipment and holding training classes on proper installation and removal of this equipment, we reduced the occurrence rate of these anomalies from 30% to less than 2%. Our management authorized the purchase of an additional infrared camera, also known as a thermal imaging camera.

This paper describes the program and the findings, explains the diagnostics and illustrates the contrast between properly and improperly installed equipment.

## 1. INTRODUCTION

Mississippi Power Company began doing infrared scans, using an infrared thermal imaging camera in 1994, as a support service to our industrial and commercial customers. Over the past several years, we have come to realize the value of using infrared thermal imaging cameras to find and solve problems for our customers as well as for ourselves. Being proactive, our department added more people to keep up with the increased needs of our customers and to provide the best reliable service to our customers. We did this by purchasing additional infrared thermal imaging cameras and increasing the scope of work to include infrared scans of our substations, feeders and all of our padmount transformers rated from 750KVA up to 2500KVA. We now have three infrared thermal imaging cameras in Mississippi Power Company.

Padmount transformers are transformers that are sealed in metal containers and filled with oil. They are used to step up or down the output voltages depending on customer needs. They range in size form 50KVA to 2500KVA and vary in shape. The main reason for using padmount transformers is that they offer a wide selection of load capacity in modular, encapsulated form. Other reasons include esthetics and safety; in designated areas such as in subdivisions, encapsulated padmount transformers are safer to operate and can be placed underground, where they are out of sight and impervious to falling trees and other hazards.

The elbow problems that we found and identified with the use of the Infrared camera were put into three categories for the purpose of identifying, tracking and repairing the problems. They are contact, probe and crimp problems. With the use of the infrared camera and through training we have reduced the problems from 30% to less than 2%.

## 2. CLASSIFICATION OF PROBLEMS

My job consists of doing infrared scans for customers, on padmount transformers and on our feeders. Since additional personnel were assigned to the department, I have been able to concentrate on padmount transformers more than was possible in the past. I have used this opportunity to track and record the data from my findings. As it turned out, I discovered that we have a serious ongoing problem with padmount transformer elbows. With 400 transformers scanned, I found that 30% of the padmount transformers had an elbow problem. With experience gained from working in electrical substations for 12 years as an electrician, and from other sources, I was able to determine what caused the problems and how to correct them. After reviewing them, I classified them into three categories, contacts, probes and crimps.

The first category is the contact problem. This occurs when the female bushing is replaced after a failure. If grease is applied incorrectly on the stud of the internal winding of the transformer, when the female bushing is threaded onto the stud, it forces the grease into the contacts of the female bushing. When the transformer is energized, the grease heats up, turning into a liquid and acting like a hydraulic pump, forcing the probe backwards. This action causes the contacts to arc and eventually burn up. Similar heating will occur if the elbow is not properly seated when installed. Fig. 1 illustrates two examples of an elbow that is not properly seated due to a mechanical error or grease being applied improperly.

The second problem category is the loose probe; related to the method of removing the elbow from the transformer after the unit had been in service. When an elbow has been installed for a period of time, it creates a vacuum or suction due to the load of the transformer. To remove the elbow from the transformer, it has to be twisted back and forth several times to break the vacuum or suction it had created due to load changes. Each time the elbow is twisted counterclockwise, it causes the probe to loosen from the threaded crimp and eventually causes the probe to burn up. Through proper training and the use of a ring stick with a slide weight on it, the elbows could be removed by one person and installed properly, therefore practically eliminating this problem. Fig. 2 illustrates two examples of loose probes.

The third problem category concerns the crimp on the underground dip wire. There are two different problems associated with the crimp. The first occurs when the wrong size crimp is used. The second occurs as a result of an improperly executed crimp connection. Either one will cause overheating that will lead to a failure. Fig. 3 is an example of the result of a bad crimp connection.

## 3. CONCLUSIONS AND COST AVOIDANCE SUMMARY

Through the use of the infrared camera, we have found and solved problems that would have been disastrous if they had not been detected in time. One of the best results of doing infrared scans is that it has allowed Mississippi Power Company to greatly improve customer relations in dependability and reliability. Unscheduled outages are a big problem to a company like ours, and by using the infrared camera in routine predictive maintenance we perform, we have greatly reduced our customers' outages.

If a padmount transformer elbow were to fail for one of our larger customers, the average time to get the customer back to 100% production would be about four hours of outage time. Several of our customers estimate their losses to be about $1,000 a minute when they are out of power due to an elbow failure problem. This computes to a $240,000 customer loss for an outage.

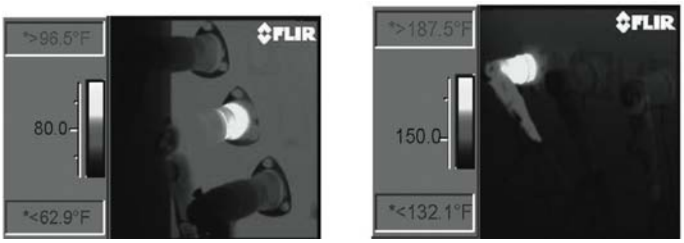

Figure 1. Two examples of heating on a padmount transformer due to improper elbow installation that will lead to contact damage

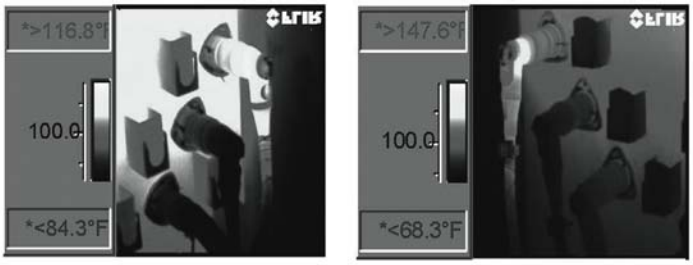

Figure 2. Two examples of heating on a padmount transformer due to loose probes

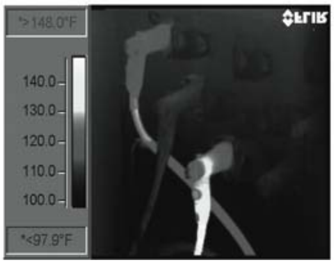

Figure 3. Overheating of an elbow caused by a bad crimp connection

By using the infrared camera to find the problems, identify and fix the problems on a controlled outage situation, Mississippi Power Company and our customers have shared in the rewards. The elbow problems found on padmount transformers were found, identified and fixed, reducing the problem by 28% through proper training of everyone involved with installation and removal of padmount transformer elbows. This saved Mississippi Power Company from loss of revenue, having to pay overtime and from destruction of expensive equipment, thereby improving customer relations and satisfaction. Also, the customer benefited greatly from Mississippi Power Company being proactive by offering infrared services to them. The bottom line is that the infrared camera is a win/win for everyone. It is one of the best purchases a company can make. Not having an Infrared camera in our business would be like going back into the Stone Age.

# Determining Distribution Substation Transformer Optimal Loadings Using a Reliability Cost-Benefit Approach

**By A. A. Chowdhury, Fellow, IEEE, L. Bertling, Member, IEEE and D. E. Custer, Member, IEEE**

## I. INTRODUCTION

Distribution substation transformers represent a significant portion of the costs associated with the distribution system, which emphasizes the importance of effective use of transformer capacity [1]-[5]. This requires consideration of not only the cost of the capacity, but also the reliability performance associated with various loading philosophies. As loading increases on the substation transformers, there is less available capacity for contingency situations that frequently occur on the distribution system.

Both normal loading and emergency capabilities must be considered in determining system contingency capacities.

These two aspects must be taken into account simultaneously because if transformer emergency ratings do not exist, it is necessary to lower normal loading levels to maintain acceptable reliability. If, however, emergency ratings are available and sufficiently high, the normal loading level can approach the top nameplate rating while maintaining the overall system reliability.

Since there is a cost associated with purchasing transformers with an emergency rating, it is necessary to determine the extent to which the emergency rating is necessary to provide reliable service. While the emergency rating provides a benefit of not having to reserve normal capacity, which can reduce or delay capital costs, there is a point at which further increase of emergency capability provides only marginal reliability improvements. Therefore, a cost-benefit analysis, which takes into account customer value of reliability, must be performed to determine appropriate normal loading guidelines for existing transformers and appropriate emergency rating criteria for new transformer purchases [6]-[9].

This article presents a novel reliability cost-benefit approach, taking into account customer value of reliability, to compare different transformer loading philosophies while simultaneously considering varying levels of transformer emergency capability. Using this cost-benefit approach, guidelines for optimal loading of existing transformers can be established. The developed methodology can also be used to establish standard emergency rating criteria for purchasing new transformers, which will optimize reliability performance against cost. The developed methodology is illustrated using real system examples.

## II. RELIABILITY COST-BENEFIT APPROACH

Based upon transformer loading, transformer and feeder emergency capability, and accepted failure rates, a yearly expected unserved energy (EUE) cost can be computed for any loading philosophy. This is accomplished by considering transformer and feeder failures and calculating the available backup capacity at different load levels. If the available backup capacity is less than that required to completely restore service following the failure, then there will be unserved energy costs associated with the outage. The unserved energy cost for each outage is then multiplied by the probability of the outage occurring and weighted by the probability of the outage occurring at the given load level using the substation load duration curve. Summing the weighted unserved energy costs results in the expected yearly total for the loading philosophy under consideration. The total expected outage cost is the sum of the transformer outage cost calculated using the algorithm in Subsection A and feeder outage cost calculated by using the algorithm in Subsection B.

The developed algorithms associated with the new reliability cost-benefit models for computing transformer and feeder outage costs are presented in the following.

### A. Steps for Computation of Transformer Outage Cost

**Step 1: Compute hourly load for transformer**

Hourly transformer load = (Maximum loading, which is % of nameplate load) x (%daily peak load at hour i) x (%load at annual five-step load duration model)

**Step 2: Compute available backup capacity**

Available backup capacity is lesser of:

1. (# of feeder ties) x (emergency feeder capacity – feeder load), OR
2. (# of adjacent transformers) x (transformer emergency capacity – transformer load)

In Item 1, the emergency feeder capacity is 11.6 MVA. After hour #14 of the outage, assume another 18 MVA of backup capacity is available due to mobile transformer arriving.

**Step 3: Calculate hourly unserved load and cost**

Hourly unserved load = (Available backup capacity) – (transformer load)

Hourly cost = (Hourly unserved load) x (outage cost/kWh) In this paper, the outage cost used is $19.68/kWh.

**Step 4: Sum hourly costs for 24 hour period**

Total daily unserved energy cost =

$$\sum_{i=1}^{24} HourlyCost_i$$

**Step 5: Compute weighted cost**

Weighted unserved energy cost = (Total daily cost) x (transformer failure rate) x (probability of being at the particular load level)

**Step 6: Repeat Steps 1-5 for each load level of the five-step annual system load duration curve**

**Step 7: Compute total expected annual unserved energy cost**

Total expected unserved energy cost =

$$\sum_{i=1}^{5} Weightedunservedenergy\,cost_i$$

### B. Steps for Computation of Feeder Outage Cost

**Step 1: Compute hourly feeder load**

Hourly transformer load = (Maximum loading which is % of nameplate load) x (%daily peak load at hour i) x (%load at annual five-step load duration model)

Hourly feeder load = (Hourly transformer load) / 4 (assuming 4 feeders per transformer)

**Step 2: Compute available backup capacity**

It is assumed that the outaged feeder has one tie to an adjacent substation and one tie to a feeder from the same substation.

Available backup capacity is lesser of:

(Capacity from feeder at the same substation) + (Capacity from the feeder of the adjacent substation)

Where,

Capacity from feeder at the same substation = (Feeder emergency rating – feeder load). In this paper, the feeder emergency rating is considered at 11.6 MVA.

Capacity from the feeder of the adjacent substation = the lesser of the:

1. (Feeder emergency rating – feeder load), and
2. (Transformer emergency rating – transformer load)

**Step 3: Calculate hourly unserved load and cost**

Hourly unserved load = (Feeder load) – (available capacity)

Hourly cost = (Hourly unserved load) x (outage cost/kWh)

In this article, the outage cost used is $19.68/kWh as in for the transformer case.

**Step 4: Get average unserved hourly cost for 24 hour period**

Average hourly outage cost =

$$\sum_{i=1}^{24} HourlyCost_i / 24$$

**Step 5: Compute weighted cost**

Weighted unserved energy cost = (Average hourly cost) x [feeder length x feeder failure rate x feeder outage duration] x (probability of being at the particular load level)

**Step 6: Repeat Steps 1-5 for each load level of the five-step annual system load duration curve**

**Step 7: Compute total expected annual unserved energy cost**

Total expected unserved energy cost =

$$\sum_{i=1}^{5} Weightedunservedenergy\,cost_i$$

**Step 8: Compute weighted total outage cost**

Perform weighting of the total outage cost calculated in Step 7 by 50% to account for failures occurring and not taking out the entire feeder. Then multiply the computed cost by 4 to account for all substation feeders.

Total weighted cost = Total unserved cost x 0.5 x 4

Total customer outage cost is the sum of the total outage cost for transformer outage and the total outage cost from feeder outage.

Differences in capital costs required to implement each loading philosophy can then be compared against the differences in unserved energy costs using a cost-benefit approach. The results of the analyses can be used to determine the most effective use of existing transformers and to determine emergency specifications for future transformer purchases.

## III. DATA AND ASSUMPTIONS

Data for equipment outage, customer outage cost, five-step load duration curve and a list of assumptions common to all of the scenarios considered are summarized in the following.

Any assumptions specific to a particular scenario will be listed separately.

- Transformers considered in the study are all loaded identically, and the assumed failure rate is 0.011failures per transformer-year.
- It takes fourteen hours to install a mobile transformer.
- The mobile transformer has an 18 MVA rating.
- It takes five days to install a spare transformer.
- Transformer load is split evenly between four feeders it serves.

- Feeders have a failure rate of 0.2 failures per mile-yr, and are each 3.5 miles long.
- Feeder outages last 4 hours on average.
- Feeders have an emergency rating of 11.6 MVA.
- Feeder outage costs are multiplied by a factor of 0.5 to represent the fact that outages may occur at locations along the feeder where a percentage of the load can still be served by the original source.
- Following a feeder failure, it is assumed that two ties are made to restore load, one to a surrounding substation and one to another circuit served from the same transformer.
- All switching is instantaneous. Since this study is concerned with expected unserved energy costs that could be avoided by having additional backup capacity, and the period during the switching time would be unserved in all cases regardless of available capacity, this assumption will not affect the computed results.
- There are no voltage constraints when attempting to pick up circuits.
- 100% utilization of available backup capacity can be realized by switching.
- Average unserved energy costs are $19.68/kWh during the first day of an outage. The unserved energy cost increases by a factor of 10 on each successive day. Refer to Appendix B for an explanation of applying this additional factor to the unserved energy costs.

In order to calculate the annual expected load lost, the substation load duration curve is approximated with a five-step load model with corresponding exposure probability. The five-step load model with corresponding probability is shown in Table I.

| Load level | Probability |
|---|---|
| 100% (Peak) | 0.001 |
| 80%-90% | 0.025 |
| 70%-80% | 0.040 |
| 60%-70% | 0.097 |
| <60% | 0.837 |

TABLE I

Simulations are run at different load levels such as 100%, 90%, 80%, etc. and annual unserved load is calculated by weighting the results of each simulation by the percent of the year that each load level is present.

## IV. APPLICATION OF THE DEVELOPED METHODOLOGY IN DETERMINING OPTIMAL TRANSFORMER LOADING

Three disparate scenarios were analyzed in this paper in order to determine appropriate transformer loading levels for various generalized locations on an urban distribution system.

The first scenario considered was representative of a substation on the fringe of the urban system, the second scenario was a single transformer substation centrally located in the urban system, and the third scenario was a dual transformer substation centrally located in the urban system.

### A. Fringe Substation Scenario

The system in this scenario was assumed to consist of a single 33 MVA transformer substation, serving four distribution circuits and adjacent to one other single transformer substation. It was also assumed that two of the distribution circuits served from the test substation had a feeder tie to a circuit served from the adjacent substation.

Outage costs for transformer and feeder failures were calculated for the load served by the test substation under various loading philosophies, and are summarized in Table II.

In order to compare the loading philosophies on an even basis, the unserved energy costs were normalized to reflect the cost associated with serving 33 MVA of load. This normalized cost is shown in the last column of Table II.

The first case (Case 1) assumed that no transformer overload capacity existed on any of the units in the system. As transformer peak loading is reduced, the estimated unused substation capacity cost of $29,632/MVA can be compared with the reduced yearly unserved energy costs. All cost figures computed in this study are in 2004 dollars.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $237 | $0 | $339 |
| 75 | $475 | $0 | $633 |
| 80 | $13,295 | $0 | $16,619 |
| 85 | $63,553 | $0 | $74,768 |
| 90 | $139,481 | $0 | $154,979 |
| 95 | $227,546 | $42 | $239,564 |
| 100 | $632,515 | $264 | $632,779 |

TABLE II
FRINGE SUBSTATION CASE 1- NO OVERLOAD CAPACITY

The unused capacity cost is computed based upon the total original cost of a compilation of existing substations divided by the total capacity of those substations. A 5% reduction in peak loading on a 33 MVA transformer correlates to 1.65 MVA of unused capacity. Using the Utility Cost Benefit Model (UCBM) [10], the unused capacity charge for 1.65 MVA ($48,893 or a yearly charge of $7,444) was compared against the yearly benefit in reduced unserved energy costs, shown in Table II to determine the payback period associated with reducing peak transformer loading. The payback periods indicate that for this scenario, the optimal transformer loading level is 80% of nameplate. Reducing peak loading below this level would not provide reliability benefits to justify the costs.

Three additional scenarios were considered to determine the benefit that transformer emergency ratings have on the reliability performance of the test system. In these scenarios, all assumptions listed earlier are identical; the only change is that a transformer emergency rating of 10%, 20%, and 30% are assumed available for 24 hours in Case 2, Case 3, and Case 4, respectively. Tables III to V list the computed results.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $234 | $0 | $335 |
| 75 | $469 | $0 | $625 |
| 80 | $779 | $0 | $974 |
| 85 | $13,448 | $0 | $15,821 |
| 90 | $62,895 | $0 | $69,883 |
| 95 | $138,151 | $3 | $145,425 |
| 100 | $224,306 | $30 | $224,336 |

TABLE III
FRINGE SUBSTATION CASE 2- 10% OVERLOAD CAPACITY

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $234 | $0 | $334 |
| 75 | $469 | $0 | $625 |
| 80 | $779 | $0 | $974 |
| 85 | $5,830 | $0 | $6,859 |
| 90 | $38,894 | $0 | $43,216 |
| 95 | $93,483 | $3 | $98,406 |
| 100 | $157,050 | $30 | $157,080 |

TABLE IV
FRINGE SUBSTATION CASE 3- 20% OVERLOAD CAPACITY

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $234 | $0 | $334 |
| 75 | $469 | $0 | $625 |
| 80 | $779 | $0 | $974 |
| 85 | $5,830 | $0 | $6,859 |
| 90 | $38,894 | $0 | $43,216 |
| 95 | $93,483 | $6 | $98,406 |
| 100 | $156,569 | $65 | $156,634 |

TABLE V
FRINGE SUBSTATION CASE 4- 30% OVERLOAD CAPACITY

The results listed in Tables III to V indicate that as peak transformer loading is increased, the benefit of having some overload capability increases. For example, comparing the 100% peak-loading case shows (see Table II for 100% peak MVA nameplate row) that having a 10% transformer overload rating (see Table III for 100% peak MVA rating row) reduces expected unserved energy costs from around $630,000 to $220,000. However the feeder tie capacity limits the usefulness of excessive transformer emergency capacity. This is evident when comparing the difference between Case 3 and Case 4, which perform identically at all load levels except for the 100% peak-loading case. The increased transformer capacity cannot be realized because of the restrictions placed on the system by the feeder emergency rating. Using the UCBM, the payback periods indicate that for Cases 2, 3, and 4, the optimal transformer loading is 85% of top-nameplate.

This is a 5% increase from Case 1, and therefore, in order to justify the emergency rating, it must be less expensive than the cost of 1.65 MVA of substation capacity ($48,893).

### B. Centralized Single Transformer Substation

The first scenario presented in Section A utilized a fringe substation surrounded by only one other substation. This case could be considered more restrictive than a typical urban substation, which would have increased available backup transformer and feeder capacity. In order to verify if additional backup capacity would allow higher transformer loadings for centrally located urban substation, a second scenario was considered. In this scenario, it is assumed that the test system is still a 33 MVA transformer serving four circuits, but there are four adjacent substations, all of which are 33 MVA single transformer substations. It is assumed that each of the four circuits have feeder ties to an adjacent substation. Tables VI to VIII present the computed results.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $9 | $0 | $11 |
| 85 | $16 | $0 | $19 |
| 90 | $41 | $0 | $46 |
| 95 | $54,561 | $23 | $57,456 |
| 100 | $183,327 | $66 | $183,393 |

TABLE VI
SINGLE TRANSFORMER SUBSTATION CASE 1-NO OVERLOAD CAPACITY

The computed results indicate that the centralized transformer can be loaded much closer to nameplate than the fringe transformer and still maintain high reliability. Even in the case where it is assumed that no transformer emergency rating is available, unserved energy costs do not increase dramatically until 95% loading is reached.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $9 | $0 | $11 |
| 85 | $16 | $0 | $19 |
| 90 | $38 | $0 | $42 |
| 95 | $124 | $2 | $133 |
| 100 | $10,579 | $17 | $10,596 |

TABLE VII
SINGLE TRANSFORMER SUBSTATION CASE 2-10% OVERLOAD CAPACITY

Using the UCBM to calculate the payback periods associated with reducing peak loading for this system, it was determined that optimal loading was 90% of top-nameplate if no transformer overload exists. If an emergency rating of 10% or greater is available, then the optimal loading is 95% of topnameplate.

So, similar to the fringe case, adding the emergency capability provides for a 5% increase in peak loading. This means a capital expense of $48,893 or less would be justifiable when purchasing the emergency rating.

### C. Centralized Dual Transformer Substation

The third scenario whether a higher loading criterion could be established for dual transformer substations is considered.

The reliability benefit of a dual transformer substation is that the transformer emergency rating of the second unit would provide on-sight partial backup capacity, which would not be restricted by feeder backup capability. Similar to the Scenario in Section B, it was assumed that four single 33 MVA transformer substations surrounded the test substation. The only change was that in this scenario, the test substation consisted of two 33 MVA units instead of one. Tables IX to XI present the computed results.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $9 | $0 | $11 |
| 85 | $16 | $0 | $19 |
| 90 | $38 | $0 | $42 |
| 95 | $124 | $2 | $133 |
| 100 | $9,617 | $16 | $9,633 |

TABLE VIII
SINGLE TRANSFORMER SUBSTATION CASE 3-20% OVERLOAD CAPACITY

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $0 | $0 | $0 |
| 85 | $4 | $0 | $5 |
| 90 | $14 | $0 | $16 |
| 95 | $31,904 | $42 | $33,625 |
| 100 | $162,224 | $121 | $162,345 |

TABLE IX
DUAL TRANSFORMER SUBSTATION CASE 1-NO OVERLOAD CAPACITY

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $0 | $0 | $0 |
| 85 | $1 | $0 | $1 |
| 90 | $6 | $0 | $7 |
| 95 | $15 | $3 | $19 |
| 100 | $26 | $30 | $56 |

TABLE X
DUAL TRANSFORMER SUBSTATION CASE 2-10% OVERLOAD CAPACITY

The results presented in Tables IX to XI show that the existence of the second transformer in the substation would provide improved reliability performance at higher load levels.

Using the UCBM, payback periods were computed for each case, resulting in an optimal loading of 90% top-nameplate if no transformer emergency rating existed. If an overload rating of 10% or greater is available, then it is possible to load to 100% of top-nameplate. Although in terms of reliability performance, it would be acceptable to load the units to top nameplate, some margin should be left for unexpected load growth that could occur within a year. Therefore, a peak transformer loading of 95% of top nameplate should be used.

Adding the emergency capability provides for a 5% increase in peak loading. This means a capital expense of $48,893 or less would be justifiable when purchasing the emergency rating.

| Peak MVA % of Nameplate | Annual EUE cost (xfmr outage) | Annual EUE cost (feeder outage) | Total annual cost for 33 MVA |
|---|---|---|---|
| 70 | $0 | $0 | $0 |
| 80 | $0 | $0 | $0 |
| 85 | $0 | $0 | $0 |
| 90 | $2 | $0 | $2 |
| 95 | $9 | $3 | $12 |
| 100 | $18 | $30 | $48 |

TABLE XI
DUAL TRANSFORMER SUBSTATION CASE 3-20% OVERLOAD CAPACITY

## V. APPLICATION OF THE DEVELOPED MODEL IN DETERMINING EMERGENCY LOADING CRITERIA FOR EXISTING UNITS

A normal industry practice is to purchase transformers with 1-hour and 7-hour emergency ratings; however, the utility operators prefer an appropriate emergency rating cycle consisting of a 2-hour and a 12-hour emergency rating. The 2-hour rating takes into consideration the call-out period and the driving time required to perform the initial load transfers. At the end of the second hour, the transformer load must be reduced to its 12-hour emergency rating; it will then need to maintain that load level or less for up to twelve hours. After the twelve additional hours, the load must be reduced to the top nameplate rating of the transformer. It is assumed that the 14-hour period (two hours plus twelve hours) is sufficient time to lower the transformer load through installation of a mobile substation and/or load transfers.

The Electric Power Research Institute (EPRI) PT Load 6.0 [11] computer model is capable of simulating emergency rating cycles such as the one described earlier. For a given pre-loading cycle and ambient temperature cycle, it is also able to calculate emergency ratings depending on specified maximum limits for core temperature, top oil temperature, and loss of life. It is assumed in this article that a utility's standard is to designate a core temperature limit of 150 degrees Celsius, a top-oil temperature limit of 110 degrees Celsius, and a maximum loss of life of two percent per event.

Since a worst-case contingency would be a failure on peak day, the ambient temperature cycle model followed a curve for a typical peak day with an average of 33.7 degrees Celsius and a maximum of 40 degrees Celsius (see Appendix C, Fig. 1). The pre-load cycle also matched a typical transformer load curve for a peak day (see Appendix C, Fig. 2). These criteria along with thermal performance data for samples of in-service transformers were used to determine appropriate emergency ratings based on the transformer class. The sample of transformers consisted of a variety of different manufacturers and ages. These results have been summarized, and give the following accepted ratings. These ratings apply to the transformer; however there may be equipment in series with the transformer which prevents the full use of the emergency overload rating.

### A. Transformers Purchased Without Emergency Ratings

A 10% emergency overload rating shall be applied to transformers base rated 12 MVA and above purchased without emergency ratings, provided there are no other mitigating circumstances which would prevent the transformer from having an emergency rating. The 10% emergency overload can be applied for a 14-hour period. Refer to Appendix A for additional detail concerning the overload rating for these units.

### B. Transformers Purchased With Emergency Ratings

69-15 KV, 15/20/25 MVA Transformers

Using the stated criteria above and EPRI PT Load 6.0, emergency ratings for these transformers were determined.

These transformers will be rated for emergency loading as follows:

- Up to 40 MVA for the first two hours of contingency
- Up to 33 MVA for the next twelve hours of contingency
- Top nameplate loading before and after the fourteen hour period

### 69-15 & 161-15 KV, 20/26.7/33.3 MVA Newer Transformers

Using the stated criteria above and EPRI PT Load 6.0, emergency ratings for these transformers were determined.

Depending on the nominal secondary voltage of the transformer, emergency loading limits will vary.

Transformers operating at 12.47 kV nominal voltage will be rated for emergency loading as follows:

- Up to 49 MVA for the first two hours of contingency

(49 MVA relates to switchgear emergency rating @12.47 kV. The transformer two-hour emergency rating is 52 MVA)

- Up to 43 MVA for the next twelve hours of contingency
- Top nameplate loading before and after the fourteen hour period

Transformers operating at the 13.2 kV nominal voltage will be rated for emergency loading as follows:

- Up to 52 MVA for the first two hours of contingency
- Up to 43 MVA for the next twelve hours of contingency
- Top nameplate loading before and after the fourteen hour period

Transformers operating at 13.8 kV nominal voltage will be rated for emergency loading as follows:

- Up to 52 MVA for the first two hours of contingency
- Up to 43 MVA for the next twelve hours of contingency
- Top nameplate loading before and after the fourteen hour period

In order to verify that the transformer load level at the precise time that the emergency cycle started did not affect the emergency ratings, multiple scenarios were simulated in PT Load on a particular transformer. In these scenarios, the emergency cycle was started at various points along the preload curve. Results of the scenario indicate that regardless of the loading at the time of the failure, the transformer would still operate safely at the two and twelve hour ratings previously given.

## VI. MODIFIED EMERGENCY RATING SPECIFICATION

As stated earlier, the normal emergency rating specification is based upon a 1-hour and 7-hour emergency cycle.

Although it was verified with PT Load that the ratings for this cycle are applicable to a 2-hour and 12-hour cycle, in order to align with the emergency ratings being assigned in this planning philosophy, the emergency rating specification provided with new transformer purchases needs to be modified. The following specifications should be provided for purchases of new 69-15 kV and 161-15 kV transformers with two stages of forced cooling:

- Ambient temperature follows a curve for a typical peak day with an average of 33.7 degrees C and a maximum of 40 degrees C (see Appendix C, Fig. 1)
- Load cycle for the time prior to a contingency follows a typical transformer curve for a peak day (see Appendix C, Figs. 2 & 4)
- Load cycle for the day of the failure follows the normal curve then jumps to the first emergency rating for two hours (52 MVA for units top-rated at 33.3 MVA or 40 MVA for units top-rated at 25 MVA), then maintains the second emergency rating for twelve hours (43 MVA for units top-rated at 33.3 MVA or 33 MVA for units top-rated at 25 MVA). See Appendix C, Figs. 3 & 5
- Emergency hot spot limit of the transformer is 150 degrees C
- Emergency top oil limit of the transformer is 110 degrees C
- Loss of life not to exceed two percent for each fourteen hour loading cycle described

It should be noted that new transformers should be purchased using an evaluation function which takes the loss factors of the transformers into consideration. This evaluation function is the sum of the following: purchase price, the no load loss coefficient multiplied by the no load losses and the load loss coefficient multiplied by the load losses. Using this evaluation function, the manufacturers generally have to use copper windings to lower load losses and a good core to keep the no load losses down. Therefore, achieving the emergency rating for the transformer is not difficult or expensive because much of the overload capability is already being built into the transformer.

## VII. OTHER LIMITING FACTORS

Even though a transformer may have emergency ratings, the ratings of other equipment in the substation limit the ability to fully utilize the emergency capacity. In particular, the switchgear and cables could limit the amount of additional load the transformer can serve. If these factors are taken into consideration, the limiting factor may not be the transformer thermal capability.

For transformers, which have 2000 Amp switchgear, the switchgear manufacturer allows an extra ten percent for one hour. In a 12.47 kV nominal system, the switchgear would be the limiting factor for the emergency rating of a 20/26.7/33.3 MVA transformer because it would reach its thermal limit before the transformer. The maximum power the transformer could be loaded to is 49 MVA, which would be the limit of the switchgear. In a 13.2 kV nominal system, the switchgear would limit the transformer to 52 MVA. The switchgear would not however, limit a transformer in a 13.8 kV nominal system.

For some substations, the secondary cables from the transformer to the switchgear could be the limiting factor. In particular, some underground cables may have thermal limits that are less than the emergency ratings of the transformer and the switchgear. Substations with overhead pipe buses have higher ratings and can carry more than the overload rating of the transformer. However, the jumpers on an overhead pipe bus may limit the amount that the transformer can be loaded.

For a 22.4 MVA rated transformer, the pipe buses have two stranded copper 500 MCM cable jumpers per phase, which have a capacity of approximately 1325 Amps. These jumpers would not limit the transformer in a 12.47 kV nominal system, because the jumpers would be able to carry 30 MVA, which is more than the emergency rating of 24.6 MVA on the transformer. (The 30 MVA equals 1325 Amps * √3 * 12.47 kV * 1.04 / 1000. The bus voltage is above 1.0 per unit.) The jumpers also would not limit the transformer on a 13.2 or 13.8 kV nominal system.

For 18/24/30-33.6 MVA transformers, the pipe buses have two stranded copper 1000 MCM cable jumpers per phase, which have a capacity of approximately 2000 Amps. This would not limit the transformer in a 12.47 kV nominal system, because the jumpers could carry 44.6 MVA, which is greater than the emergency rating of 36.6 MVA on the 18/24/30-33.6 MVA transformer. The jumpers would not limit the transformer in a 13.2 or 13.8 kV nominal system either. New 20/26.7/33.3 transformer installations use underground cables between the transformer secondary and switchgear instead of overhead pipe buses. This eliminates any limitations imposed by the jumpers; however, in some instances the cable rating may prevent the use of a 52 MVA two-hour overload and 43 MVA twelve-hour overload. The minimum relay pickup limit may also limit the ability to utilize the full emergency rating of a transformer.

## VIII. CONCLUSION

This article has presented a novel reliability cost-benefit model to compare different transformer loading philosophies while simultaneously taking into account varying levels of transformer emergency capability. It has been illustrated that using the developed value-based model, standards for loading in-service transformers can be established. Also, the developed value-based model can be utilized to establish standard emergency rating criteria for purchasing new transformers that would optimize reliability performance versus cost. The applications of the model have been illustrated using practical system examples.

## IX. APPENDICES

### A. Overload Rating of Transformers Purchased Without Emergency Ratings

The normal rating of a power transformer is based on the load level, which results in internal temperatures that are within IEEE specifications. Increasing the load beyond the normal rating increases internal temperature and accelerates the aging of the winding insulation, thereby reducing the expected life of the transformer. IEEE has developed equations predicting the loss of life associated with operation at increased internal temperatures. Since a general practice is to specify a 2% loss-of-life per overload event on new units purchased with emergency ratings, tables in the "IEEE Guide for Loading Mineral-Oil-Immersed Transformers" were referenced to determine the overload for a 24-hour period that would not exceed 2% loss-of-life. Assuming a transformer pre-loading of 100% nameplate and an ambient temperature of 40 degrees C (104 degrees F), the IEEE guide stated that an overload of 23% applied over a 24-hour period would result in 2% loss of life.

Because it is proposed to apply the emergency overload rating to transformers which are older and whose internal condition is uncertain, it was decided that a more conservative overload rating should be used. Another factor supporting a conservative overload rating is that limitations may exist with the LTC, bushings, and other transformer auxiliary equipment. It was also considered that the overload rating should be greater than 0% because of the inherent overload capability of transformers, but less than 23% for the reasons listed earlier; therefore, a 10% emergency overload rating was considered to be the optimal overload. The guidelines for use of the emergency overload rating are given in the following.

The 10% emergency overload rating:

- should not be used to serve normal peak loads. If required, switching should be performed to keep normal transformer loading at or below top nameplate,
- should not be used following a contingency, as an alternative to distribution switching, if switching solutions are available,
- should not be used to avoid bringing in a mobile substation following a transformer failure,
- can be used as part of a temporary solution to restore load following a transformer failure, until the mobile substation arrives and is installed, and
- can be used on consecutive days following a transformer failure until the spare unit can be installed, provided that all other options are exhausted (switching and the installation of a mobile substation).

In brief, the emergency rating is to be used only as a last resort following a contingency on the system. The basic principle behind assigning the 10% emergency overload rating is to deal with the extremely rare, but severe contingencies at peak load levels. The emergency rating provides the capability to utilize a greater percentage of installed transformer capacity and maintain reliability even at peak loads. It is expected that occurrences requiring use of the emergency overload rating will be minimal and therefore the small increase in risk is offset by reduction in capital expenditures and/or customer outages.

### B. Description of Unserved Energy Cost Adjustment

The typical outage cost of $19.68/kWh was considered to be insufficient in capturing impacts of outages that would exceed a one-day duration. Initial calculations based upon a constant unserved energy cost resulted in the ability to justify transformer normal peak loading levels that could potentially lead to large amounts of load (>10 MW) remaining unserved for an extended period following the failure of a single transformer. The amount of time required to install a spare transformer is approximated to be 5 days and it was concluded that the load could remain unserved for 5 days until the spare transformer is installed. It has been recognized that this situation would be unacceptable and that there would be additional socio-econo-political impacts caused by an outage of that duration, especially assuming that the outage was not related to a major weather event. The additional socio-econo-political effects of a prolonged outage are not represented in the standard unserved energy cost of $19.68/kWh. In order to capture the increasing negative effects on the utility, it was decided to include a multiplier of 10 for each additional day that the outage persisted. The result of including the multiplier is that outage costs become extremely high on the fourth and fifth day. The increased outage costs justify reducing transformer loading to a level such that if it failed at peak, the combination of the mobile substation plus the emergency capability of the surrounding transformers and distribution feeders would be capable of recovering all load.

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*[2] R. E. Brown, Electric power distribution reliability, Marcel Dekker, New York, 2004.*

*[3] R. E. Brown and M. M. Marshall, "Budget constrained planning to optimize power system reliability", IEEE Transactions on Power Systems, Vol. 15, No. 2, May 2000, pp. 887-892.*

*[4] A. A. Chowdhury, S. K. Agarwal and D. O. Koval, "Reliability modeling of distributed generation in conventional distribution systems planning and analysis", IEEE Transactions on Industrial Applications, Vol. 39, Number 5, September/October 2003, pp. 1493-1498.*

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*[10] Electric Power Research Institute, Utilitiy cost benefit analysis model (UCBM), EPRI RP1678-15, Palo Alto, CA, March 1987.*

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## *C. CYCLE LOADING*

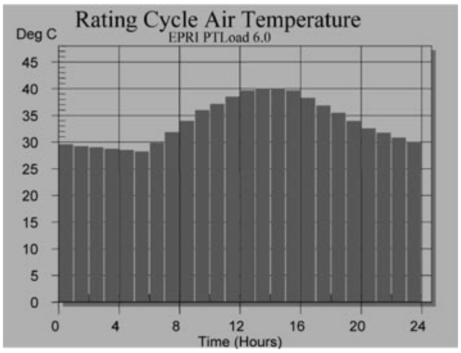


**Fig.1: Ambient temperature cycle for the day before the failure and the day of the failure.**

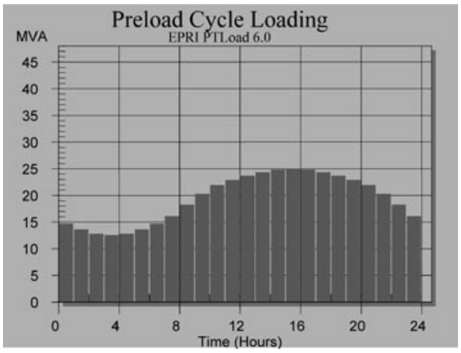


**Fig.2: Load cycle for a 15/20/25 MVA transformer the day before the failure.**

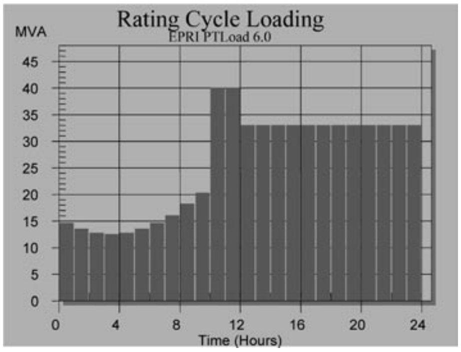


**Fig.3: Load cycle for a 15/20/25 MVA transformer the day of the failure.**

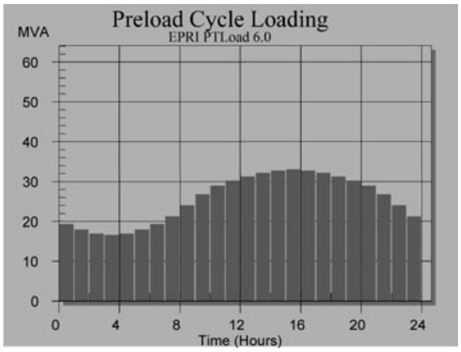


**Fig.4: Load cycle for a 20/26.7/33 MVA transformer the day before the failure.**

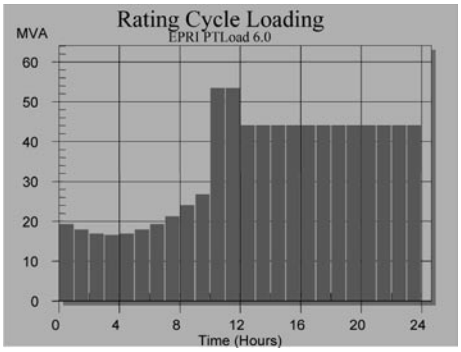


**Fig.5: Load cycle for a 20/26.7/33 MVA transformer the day of the failure.**

# Case Studies Regarding the Integration of Monitoring & Diagnostic Equipment on Aging Transformers with Communications for Scada and Maintenance

**Byron Flynn, Application Engineer, GE Energy**

## I. Abstract

Valuable information from Monitoring and Diagnostics (M&D) equipment installed on aging power transformers helps utility personnel operate and maintain critical infrastructure.

M&D systems provide valuable on-line information from power transformers including gas in oil, internal hot spot temperature, insulation aging moisture content in winding insulation, bubbling temperature, and OLTC position tracking. This article reviews several methods of integrating M&D equipment to provide this information to SCADA and maintenance systems.

## II. Background

A discussion of Transformer Monitoring and Diagnostics has a basis on the fundamental construction of a transformer. The transformer is basically a machine consisting of several parts: This discussion, while seemingly overly simplistic, is useful to provide a basis of failure modes and monitoring and diagnostic methods.

The core and coil are the fundamental components of a transformer providing the coupling of magnetic flux between two windings. The core and coils are placed in a tank filled with oil and connected to bushings.

The cooling system and control cabinet are the remaining fundamental components of a transformer. Additionally, many transformers in distribution substations include a Load Tap Changer (LTC) that provides additional voltage control on the distribution feeder.

There have been significant efforts to understand the various failure modes of power transformers. Applying the fundamentals of an FMEA analysis consisting of:

- Identify functions
- Identify failure modes
- Identify failure causes
- Identify effects of failure modes
- Identify criticality or risk
- Select on-line monitoring to match characteristic of developing failure cause(s)

The analysis of the failure modes

of the various components then leads to a review of the inspection and maintenance procedures of power transformers. Then applying Reliability Center Maintenance (RCM) tools to the failure mode analysis information helps a utility design a monitoring system to optimize utilization and eventual life cycle.

Preventive and predictive maintenance:

Reduces the risk and costs of unexpected failure

Actual conditions drive maintenance and repair

Extending life of assets

Reducing costs of maintenance

On-Line diagnostic condition assessment addressing common failure modes:

Multiple sensors

Multiple on-line models

All parameters are recorded automatically and continuously Trend and limit alarms

### On-Line Diagnostics Models

To deal with the potential overload of data, many utilities are installing systems with online diagnostics models. These models were installed to reduce the flood of raw data and to continuously provide information regarding the transformer health and operating history. Additionally, the Dynamic Loading Model provides a guide which can assist the dispatchers by calculating the overloading capabilities based on current operating conditisions, especially useful during critical times.

Additionally, early detection of problems, at the incipient stage, will help extend the life of the transformers. Detection of these problems is accomplished with several models which rely on various sensors installed on the transformer and in the substation, combined with other parameters manually entered. This data is then fed into industry standard and accepted models, which calculate the various outputs. These outputs are displayed and trended in the two Master Stations. These capabilities increase the useful data while significantly reducing the shear volume of data. The models focused on the main tank, the LTC and the cooling system and will be described briefly in this sec-

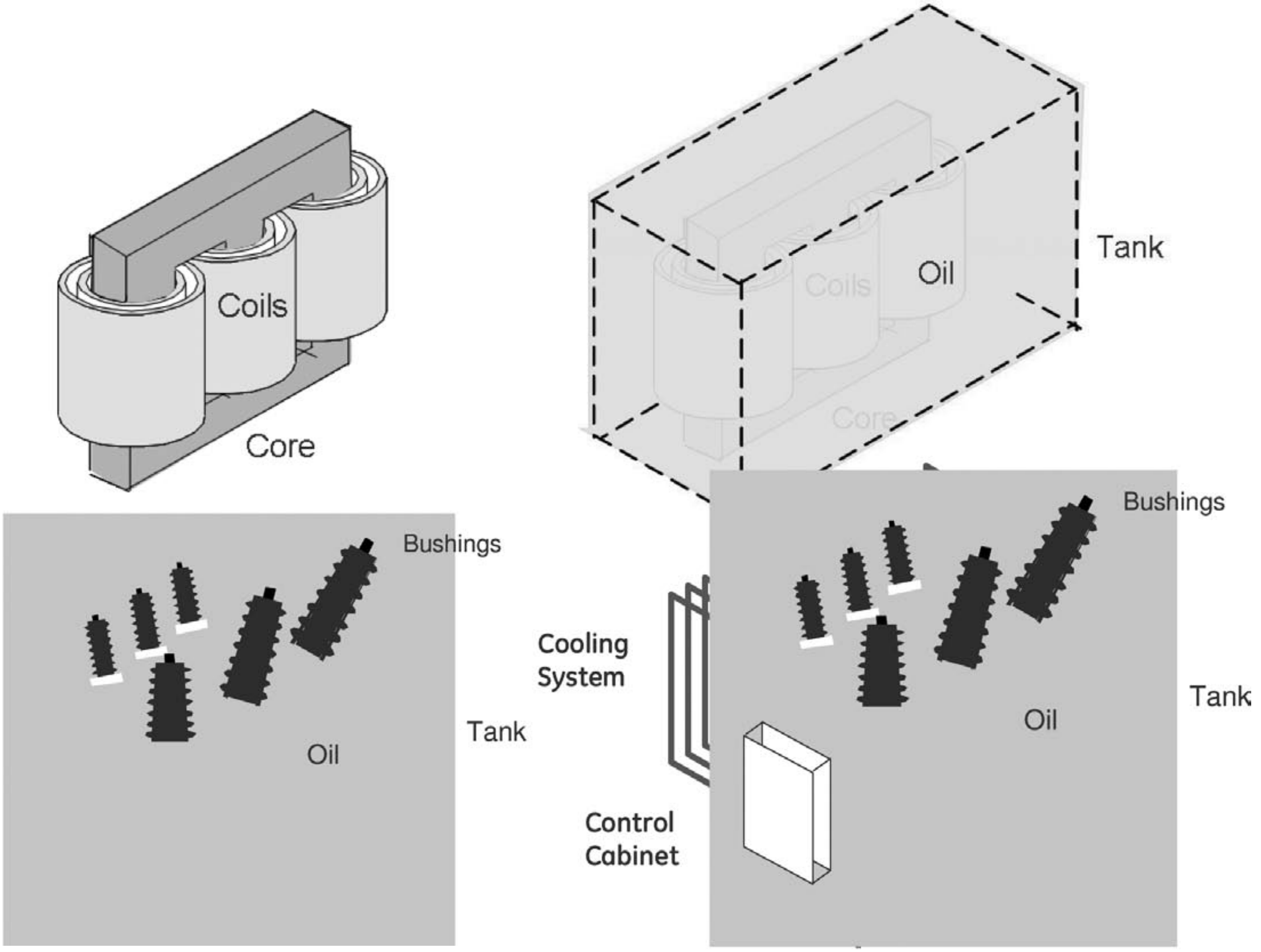


Figure 1

Basics of a Transformer

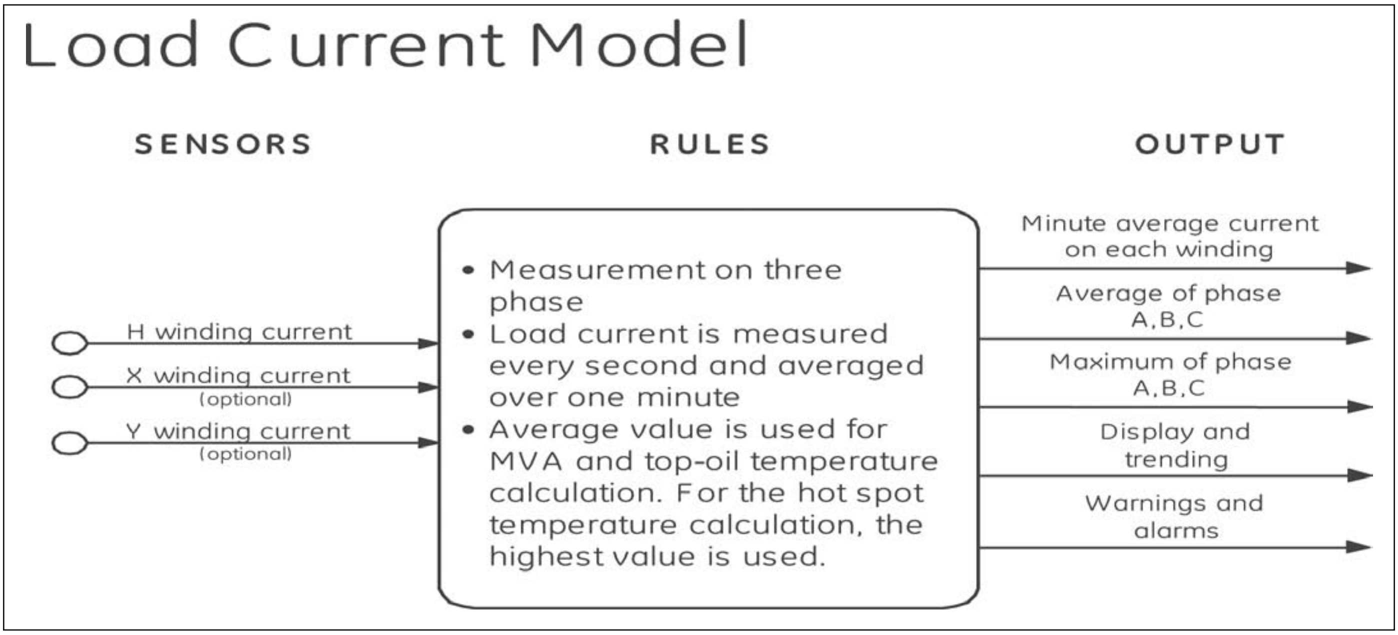

Load Current Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
• Measurement on three phase
• Load current is measured every second and averaged over one minute
• Average value is used for MVA and top-oil temperature calculation. For the hot spot temperature calculation, the highest value is used.
Minute average current on each winding
Average of phase A,B,C
Maximum of phase A,B,C
Display and trending
Warnings and alarms

Figure #2: Load Current Model

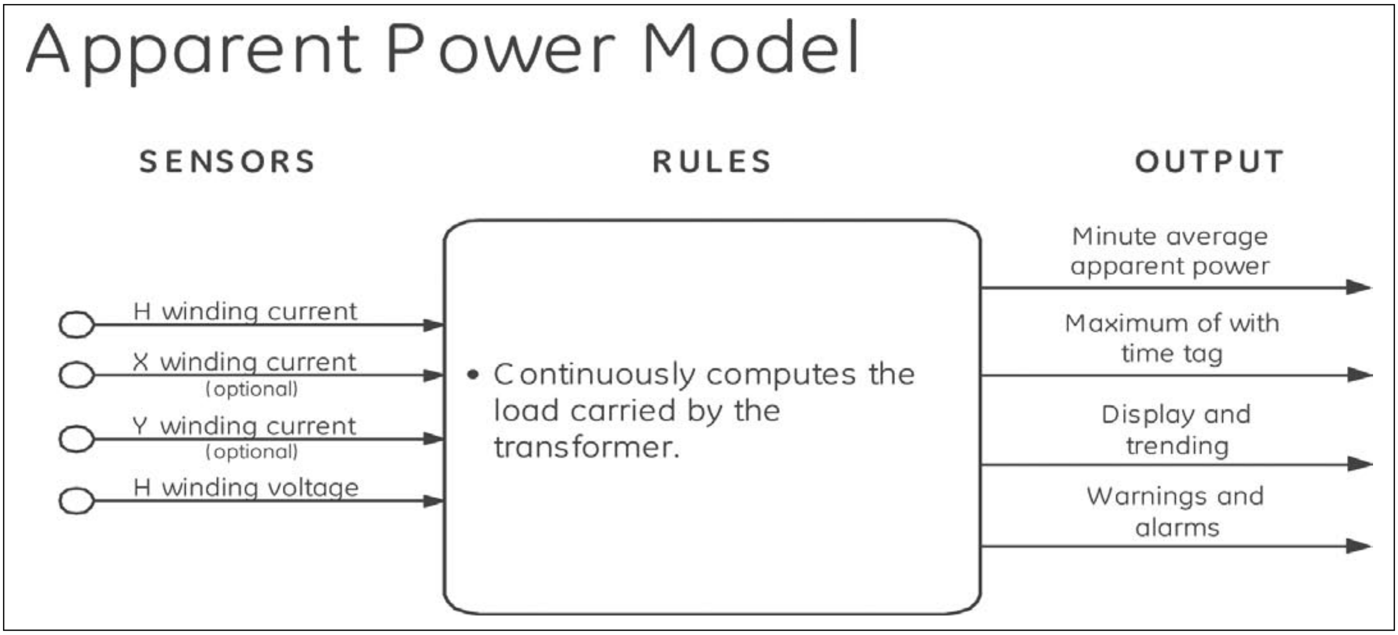

Apparent Power Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
H winding voltage
• Continuously computes the load carried by the transformer.
Minute average apparent power
Maximum of with time tag
Display and trending
Warnings and alarms

Figure #3: Apparent Power Model

tion. [1] & [2].

### Load Current Model

The first two models use routine calculations. The Load Current Model calculates average and maximum current on each winding based on one-second measurements.

This data is available for display and for trending in the Master Stations. The model's block diagram is shown below.

### Apparent Power Model

The Apparent Power Model simply calculates average apparent power (MVA) from the transformer's current and voltage. The average and maximum MVA readings are then displayed and trended. Warnings and alarms are also provided, if limits are reached.

### Winding Temperature Model

The Winding Temperature Model is based on IEEE and IEC loading guides. In accordance with these guides, it calculates the hottest spot temperature on each winding. The values are then made available for trend and display on the master stations. The following block diagram illustrates this model's inputs and outputs.

Computations are carried out according to:

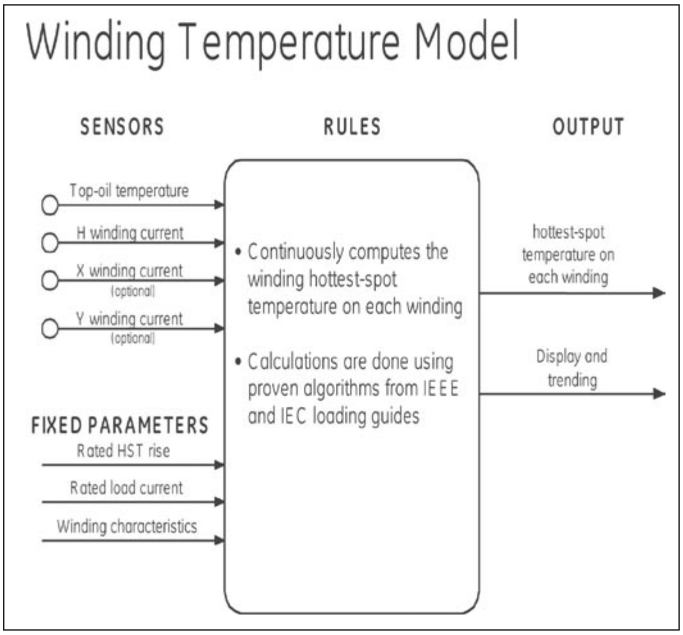

Winding Temperature Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
FIXED PARAMETERS
Rated HST rise
Rated load current
Winding characteristics
• Continuously computes the winding hottest-spot temperature on each winding
• Calculations are done using proven algorithms from IEEE and IEC loading guides
hottest-spot temperature on each winding
Display and trending

**Figure #4: Winding Temperature Model**

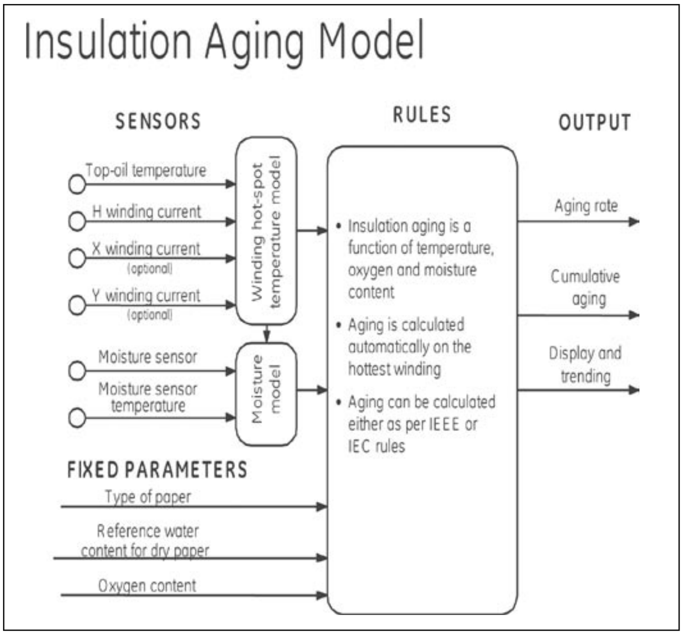

Insulation Aging Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Winding hot-spot temperature model
Moisture sensor
Moisture sensor temperature
Moisture model
FIXED PARAMETERS
Type of paper
Reference water content for dry paper
Oxygen content
• Insulation aging is a function of temperature, oxygen and moisture content
• Aging is calculated automatically on the hottest winding
• Aging can be calculated either as per IEEE or IEC rules
Aging rate
Cumulative aging
Display and trending

**Figure #5: Insulation Aging Model**

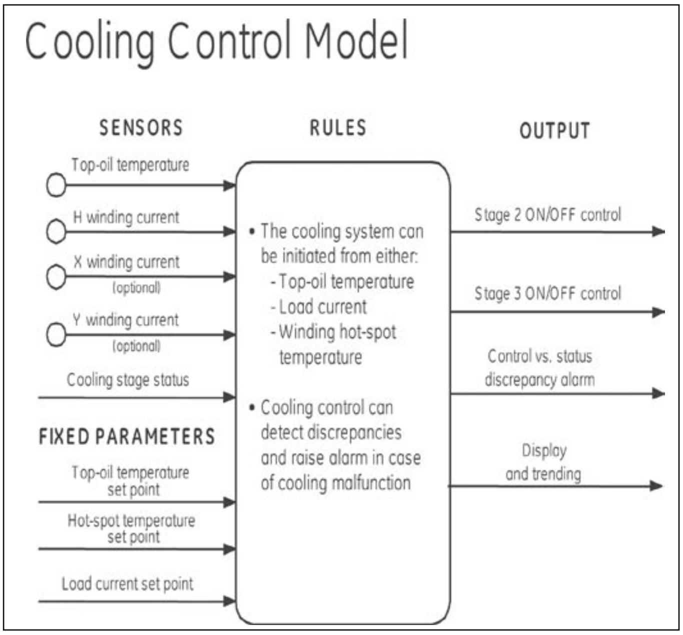
- IEC 354, Loading Guide for Oil-Immersed Power Transformers, Section 2.4, Equation 1
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers, Section 7.2.6, Equation 16, 17, 18

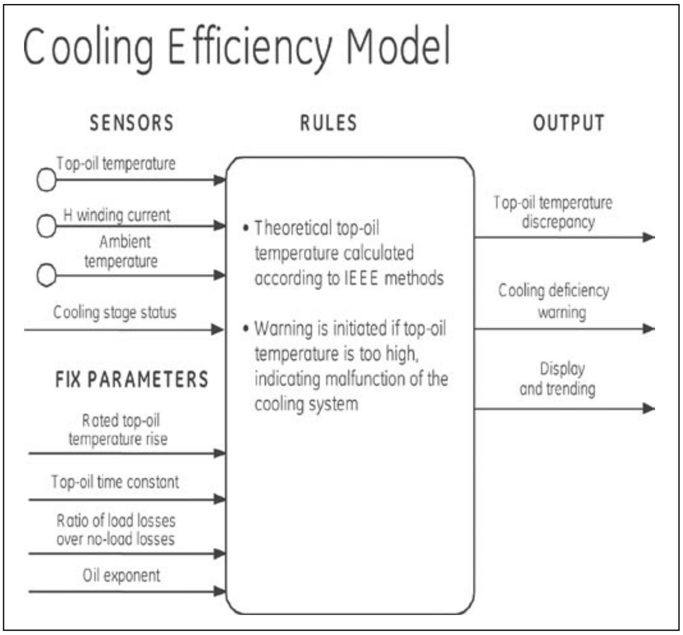
### Insulation Aging Model

The Insulation Aging Model calculates transformer aging data based on two different methods, daily & cumulative (IEEE + IEC).

The computations are carried out according to:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.6.2,
  Equation 7, 8


Cooling Control Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Cooling stage status
FIXED PARAMETERS
Top-oil temperature set point
Hot-spot temperature set point
Load current set point
• The cooling system can be initiated from either:
- Top-oil temperature
- Load current
- Winding hot-spot temperature
• Cooling control can detect discrepancies and raise alarm in case of cooling malfunction
Stage 2 ON/OFF control
Stage 3 ON/OFF control
Control vs. status discrepancy alarm
Display and trending


Cooling Efficiency Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
Ambient temperature
Cooling stage status
FIX PARAMETERS
Rated top-oil temperature rise
Top-oil time constant
Ratio of load losses over no-load losses
Oil exponent
• Theoretical top-oil temperature calculated according to IEEE methods
• Warning is initiated if top-oil temperature is too high, indicating malfunction of the cooling system
Top-oil temperature discrepancy
Cooling deficiency warning
Display and trending

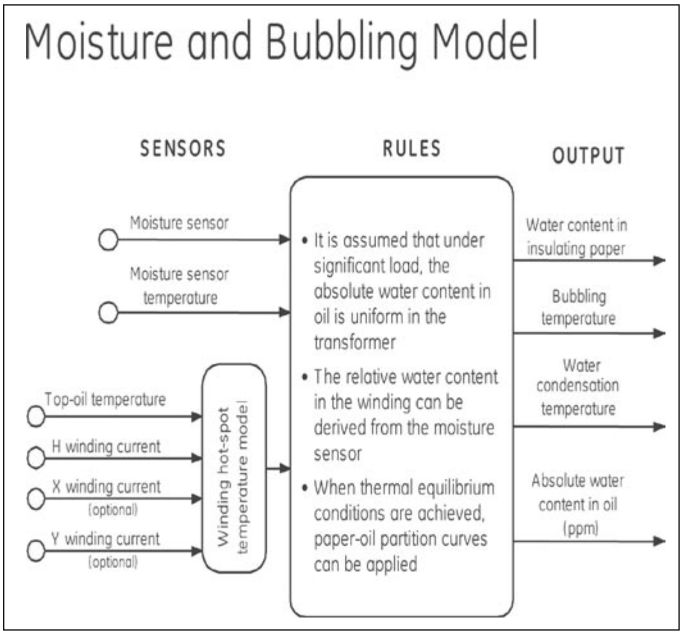
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 5.2, Equation 2 for 65°C thermally upgraded paper; Annex D, Equation D2 for 55°C normal Kraft paper.

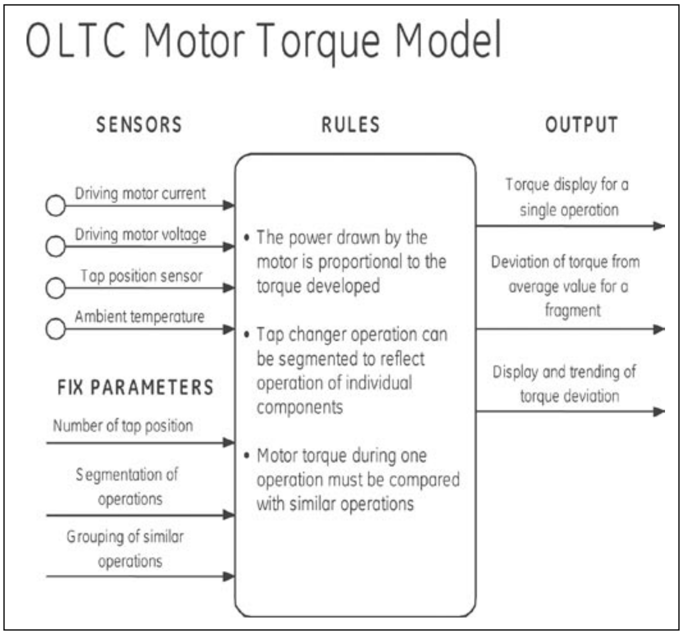
### COOLING CONTROL MODEL

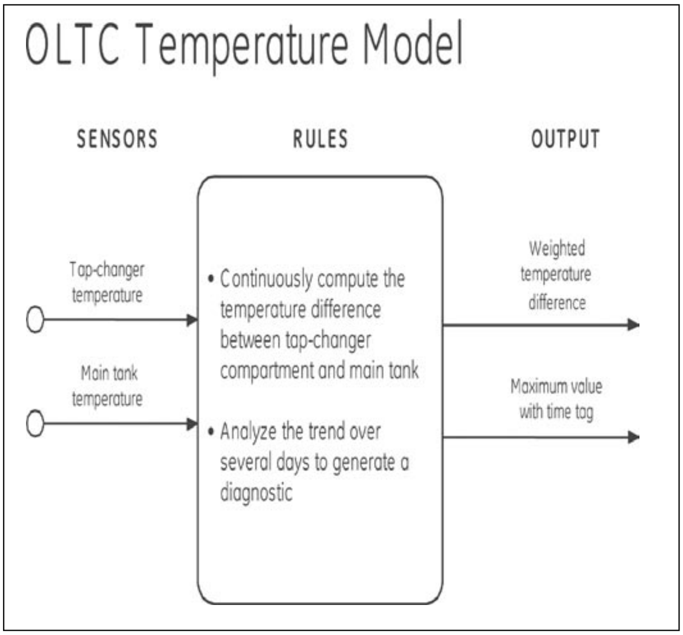
The system also can be used for cooling control using the model described in the block diagram below. The system is used as a backup.

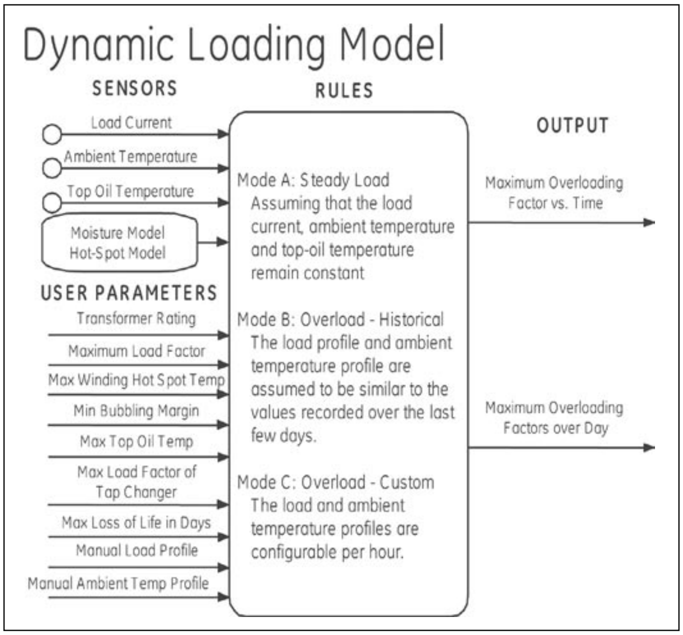
### COOLING EFFICIENCY

The Cooling Efficiency Model is used to determine if the Cooling system can lose efficiency over time due to fan failure, physical failure or coolers clogged with pollen, dirt, or nests. These conditions need to be detected before a transformer overload occurs. The model uses the


Moisture and Bubbling Model
SENSORS
RULES
OUTPUT
Moisture sensor
Moisture sensor temperature
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Winding hot-spot temperature model
• It is assumed that under significant load, the absolute water content in oil is uniform in the transformer
• The relative water content in the winding can be derived from the moisture sensor
• When thermal equilibrium conditions are achieved, paper-oil partition curves can be applied
Water content in insulating paper
Bubbling temperature
Water condensation temperature
Absolute water content in oil (ppm)


OLTC Motor Torque Model
SENSORS
RULES
OUTPUT
Driving motor current
Driving motor voltage
Tap position sensor
Ambient temperature
FIX PARAMETERS
Number of tap position
Segmentation of operations
Grouping of similar operations
• The power drawn by the motor is proportional to the torque developed
• Tap changer operation can be segmented to reflect operation of individual components
• Motor torque during one operation must be compared with similar operations
Torque display for a single operation
Deviation of torque from average value for a fragment
Display and trending of torque deviation


OLTC Temperature Model
SENSORS
RULES
OUTPUT
Tap-changer temperature
Main tank temperature
• Continuously compute the temperature difference between tap-changer compartment and main tank
• Analyze the trend over several days to generate a diagnostic
Weighted temperature difference
Maximum value with time tag


Dynamic Loading Model
SENSORS
RULES
OUTPUT
Load Current
Ambient Temperature
Top Oil Temperature
Moisture Model Hot-Spot Model
USER PARAMETERS
Transformer Rating
Maximum Load Factor
Max Winding Hot Spot Temp
Min Bubbling Margin
Max Top Oil Temp
Max Load Factor of Tap Changer
Max Loss of Life in Days
Manual Load Profile
Manual Ambient Temp Profile
Mode A: Steady Load
Assuming that the load current, ambient temperature and top-oil temperature remain constant
Mode B: Overload - Historical
The load profile and ambient temperature profile are assumed to be similar to the values recorded over the last few days.
Mode C: Overload - Custom
The load and ambient temperature profiles are configurable per hour.
Maximum Overloading Factor vs. Time
Maximum Overloading Factors over Day

following calculation methods:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.4.1,
Equation 1
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 7.2.4, Equations 8, 9, 10, 11, 15

## MOISTURE AND BUBBLING MODEL

Moisture content of paper is critical because it reduces dielectric strength and increases risk of bubbling at high load resulting in accelerates. The calculations are carried out in line with the following recommended methods:

- T.V. Oommen, "Moisture Equilibrium in Paper-Oil Insulation Systems", Proc. Electrical Insulation Conference, Chicago, October 1983
- W.J. McNutt, G.H. Kaufmann, A.P. Vitols and J.D. MacDonald, "Short-Time Failure Mode Considerations Associated With Power Transformer Overloading", IEEE Trans. PAS, Vol. PAS-99, No. 3, May/June 1980
- T.V. Oommen, E.M. Petrie and S.R. Lindgren, "Bubble Generation in Transformer Windings Under Overload Conditions", Doble Client Conference, Boston, 1995
- V.G. Davydov, O.M. Roizman and W.J. Bonwick, "Transformer Insulation Behavior During Overload", EPRIÒ Substation Equipment Diagnostic Conference V, New Orleans, February 1997

## TAP CHANGER TEMPERATURE MODEL

Over the life of the transformer, the Tap Changer is a significant source of potential maintenance issues. Many problems with the tap-changer (contact coking) lead to temperature rise in the tap-changer compartment. This failure mode is easily detected by monitoring tap-changer temperature compared to main tank temperature.

### Tap Changer Motor Torque Model

A change in the motor torque pattern is another indicator of mechanical failures of a tapchanger component. The Tap Changer Motor Torque Model provides a means of detecting a fault in the tap changer, the reversing selector, the gears or energy storage device.

### Dynamic Loading Model

The Dynamic Loading Model provides the operators with a perspective of the overloading capabilities, based on its current operating conditions. As the load grows in the area, this capability will become more critical in the operation of the transformer.

The Dynamic Loading Model is based on the following models:

- IEC 354, Section 2.4
- IEEE C57.91-1995, Section 5.2 & 7.2.6

## III. CASE STUDIES

### Case Study #1

Overall System Requirements

1. To gain remote control & monitoring of two Substations
   - By reducing outage times
   - By reducing operating costs
   - By reducing trips to the field
   - By catching problems before failures occur
   - By maintaining a healthy system.
2. To improve monitoring and load management
   - By balancing single phase loads
   - By monitoring underground for potential overload conditions
   - By managing the transformer loading and
   - By monitoring and controlling the voltage levels
3. To accommodate future SCADA System growth and to be expandable throughout the entire electrical system
   - Including the remaining substations
   - Including other distribution breakers and capacitors

The overall system installed is shown in the architecture drawing in Figure #12. The two dispatch centers communicate with the SCADA system via DNP 3.0 over IP on the SCADA System. Data Concentrators/RTUs were installed in the substations, which communicated with several Intelligent Electrical Devices (IEDs). Additionally, communications equipment was installed to support the initial system. The new communications equipment utilized available channel space on the company digital microwave system.

### New Dispatch Centers

The SCADA software was configured nearly identically at the two masters. The only other difference with the two dispatch center systems is the master stations have different IP and DNP addresses. This allowed the two systems to be operated independently. System analog and status changes and control signals are communicated to both masters over the same communication line. This is possible because the system operates over Ethernet communications. This also provided the ability to dispatch for the entire system from either master, providing additional coverage during busy times or a secondary master station if a problem occurs. The similarity of the two Master Stations simplified software configuration of the masters and the RTUs. The communications system will be discussed in further detail in a subsequent section.

### Integrated Transformer Monitoring

Two monitoring systems were installed on the two 120 MVA transformers and integrate into the system using DNP 3.0 protocol over IP. The monitoring and diagnostic (M&D) systems contain smart RTUs, which form the foundation for the diagnostic system.

These RTUs integrate data from several sensors and the transformer monitoring IEDs and perform the diagnostic models. These IEDs consist of a LTC monitor, and sensors which monitor combustible gases and moisture of the oil in the main tank. The M&D RTUs then analyze the data using several of the diagnostic models. It is important to operations and maintenance personnel that the transformer monitoring system reduce the amount of raw data provided. All the intelligent models described in the previous section were implanted which provided information regarding the health of the transformers. These models focused on three main areas; the main tank, the cooling system, and the Load Tap Changer (LTC).

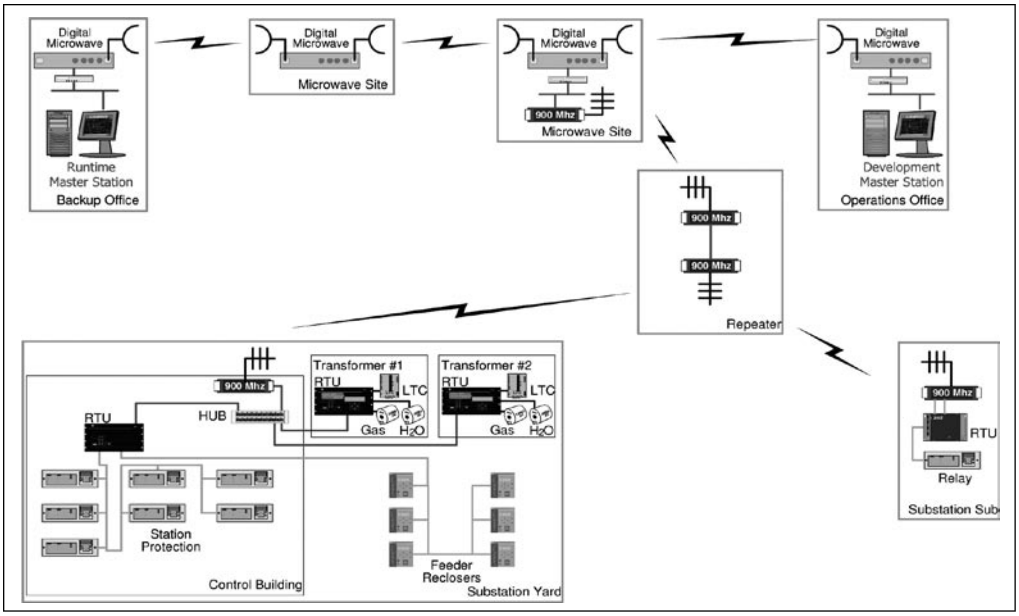


Figure #12: Case #1, System Architecture

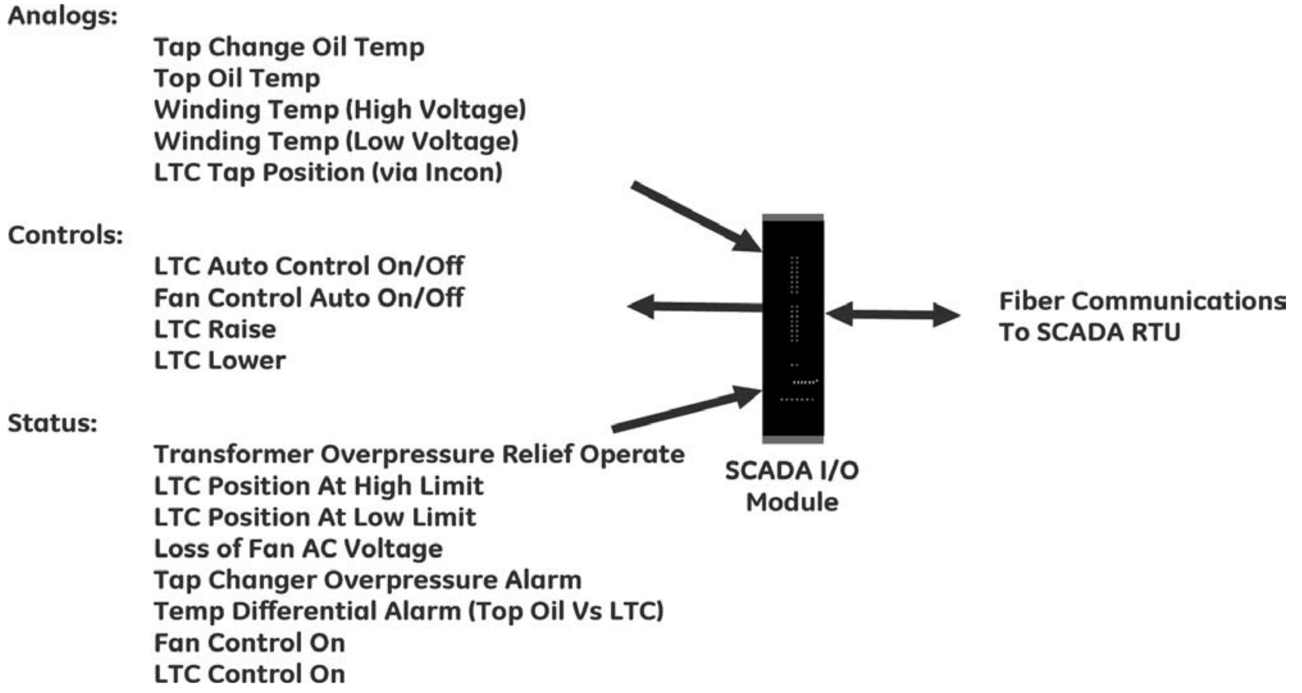

Analogs:
Tap Change Oil Temp
Top Oil Temp
Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position (via Incon)
Controls:
LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower
Status:
Transformer Overpressure Relief Operate
LTC Position At High Limit
LTC Position At Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On
SCADA I/O
Module
Fiber Communications
To SCADA RTU

Figure #13: Case #2, System Architecture

### Case Study #2

This system utilizes on-line monitoring with no on-line diagnostics. It provides an inexpensive method to capture data from the transformer and assist in off-line diagnosis of transformer problems.

### Distributed I/O

This system is based on distributed SCADA I/O modules communicating back to an RTU in the control building. The I/O modules have-on board digital status, analog and control allowing the transformer monitoring system to be integrated into the SCADA system.

Analogs – the following values are used to detect problems with the LTC or the main tank. Additionally, indication of the LTC position is provided which can be used to determine operation of the LTC and potential problems such as LTC hunting or subsequent tracking of the number of operations of each tap between maintenance intervals.

These values include:

Tap Change Oil Temperature – to detect problems with the LTC

Top Oil Temperature – can detect problems with the tank or cooling system

Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position

Controls – provides on/off control of the LTC and Fan automatic systems. In addition, remote control of the LTC is also provided. The points included are:

LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower

Status – The status points monitored include indication of the control points and on other transformer alarm points. The Top Oil vs. LTC temperature alarm is a primary alarm indication of LTC problems whenever the LTC tank temperature exceeds the top oil tank temperature. The status points include:

Transformer Overpressure Relief Operate
LTC Position at High Limit
LTC Position at Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On

### Case Study #3

This system is installed on a power plant Generator Step Up (GSU) transformer. From manual oil samples collected from the transformer, it was found that this GSU was gassing above normal operational parameters. The transformer was taken off line in mid October of 2006 for maintenance. On-Line monitoring is critical for this transformer as failure could result of a loss of revenue exceeding $100K per day.

The customer flushed and filtered the oil and inspected the transformer for any potential problems. A continuous on-line gas PPM monitoring was installed to provide the Power Plant operations indication of combustible gases in the oil.

### System Description

This system uses an on-line gas monitor integrated into station RTU which feeds data to the DCS system using Modbus over IP. The on-

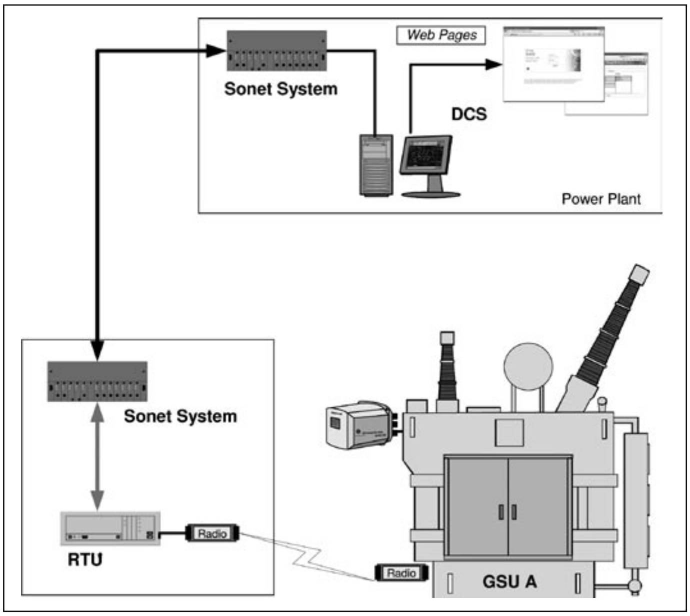


Figure #14: Case #3, System Architecture

line gas monitor reports the following data:

- PPM value of composite combustible gas measurement
- Short term and long term rate of change of PPM value of composite combustible gas measurement
- Relative saturation (humidity) of moisture dissolved in oil (%RH)
- Hourly average of %RH and PPM of water in oil
- Computes the PPM water content in oil
- Computes the water in oil condensation temperature

Monitoring these parameters at the plant will help reduce the potential of an unexpected outage due to failure of the transformer.

## Case Study #4

This system is installed at another utility on a series of power plant Generator Step Up (GSU) transformers. This utility had similar concerns about the potential revenue lost from unexpected GSU failure. Much of their fleet of GSU transformers are over 30 years old. This utility also was looking for a method of reducing maintenance costs and loading on limited maintenance resources by moving to a condition based maintenance system. On-Line diagnostics was installed to provide real time information to the plant control operators on their DCS systems and to their SCADA system.

### System Description

This system uses an on-line diagnostic system integrated into station DCS using Modbus over IP. All the diagnostic models described in Section II were installed and integrated into the DCS critical data was also provided to the SCADA system via web pages from the DCS system. The on-line diagnostics system was installed because the models reduced the amount of raw data being handled by the operators and the value of calculated output data which then generates an alarm when the model detects a problem. Over 150 gas monitors and 40 diagnostic systems have been installed to date, the utility plans to install an additional 40 units over the next three years.

## Case Study #5

This case study describes a system installed on two large 400MVA station transformers.

The utility decided to install a diagnostic system because of the critical nature of these transformers and the costs of an unexpected failure. The diagnostics systems for these transformers, shown in the photos in the following figure, were installed late in 2002.

### System Description

This system includes the diagnostics capabilities similar to the previous example but also integrated bushing monitoring. The following listing contains the values being monitored in this case study.

Functions:

- Monitor all critical parameters
- Top Oil Temp
- Ambient Temp
- Bottom Oil Temp
- Dissolved gas in oil
- Moisture in oil
- Load current
- Voltage
- OLTC position
- OLTC remote control
- HV & LV Bushings

The Bushing monitor sensors are installed on the high- and low-voltage bushing on each phase. This allows the system to monitor the leakage current on each bushing and detect potential problems.

This system communicates directly with the SCADA system via DNP 3.0.

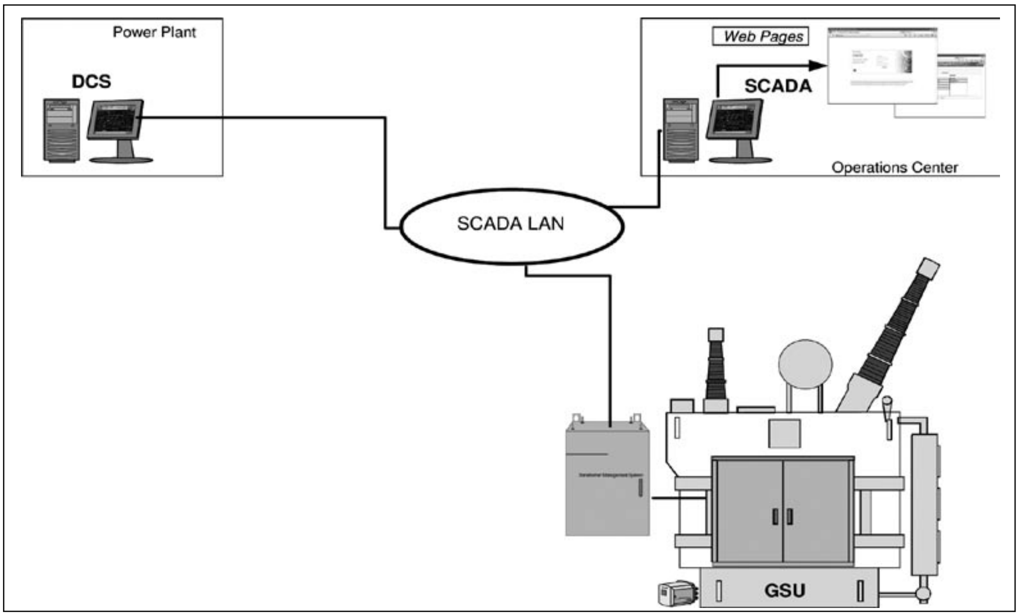


Figure #12: Case #1, System Architecture

Figure #16: Case #5, Transformer Photos

## Case Study #6

This system highlights a few additional communications and functional capabilities.

First, this system provides the diagnostic and monitoring of previous systems, including bushing monitoring.

The communication system between the transformers and the control building consists of a DNP IP communications over the local power line carrier system. It utilizes a secure PLC (Power Line Carrier) system that low-voltage wiring into an intelligent highspeed broadband networking platform. This system is useful when there is no economical method of adding communications between the transformer and the control building. This system also includes a smart gateway which has a DNP connection to a DCS and Https web-based server access by authorized users.

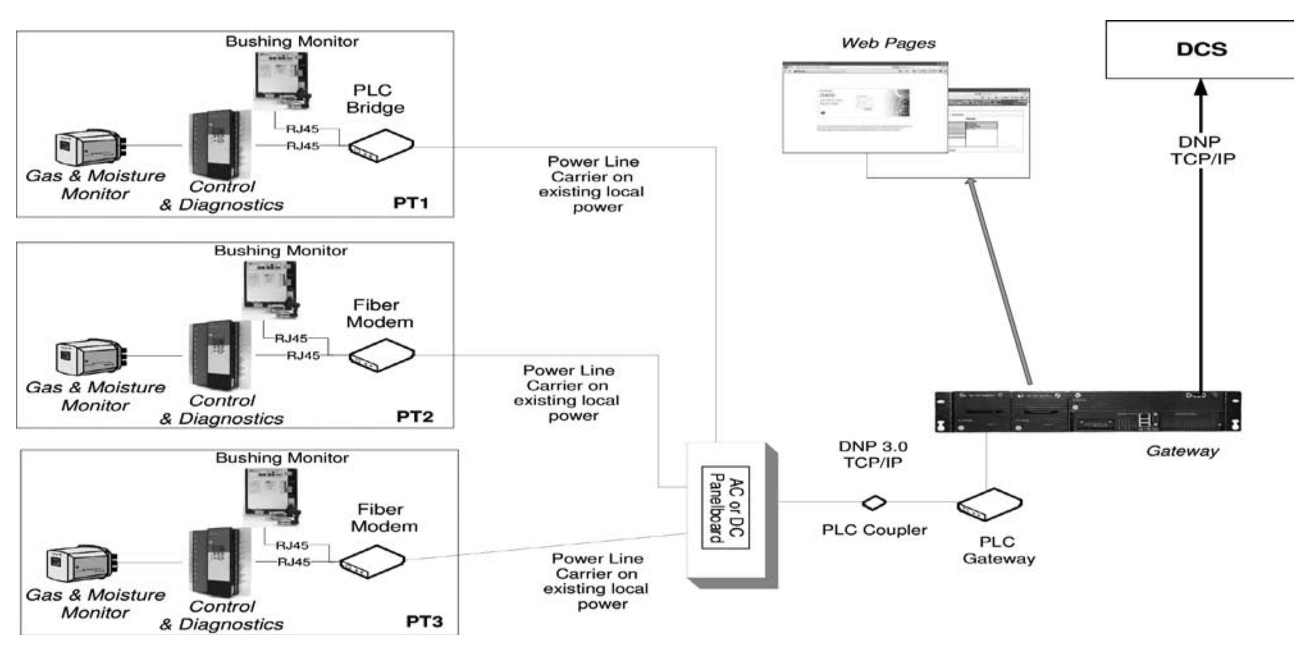


Figure #17: Case #6, System Architecture

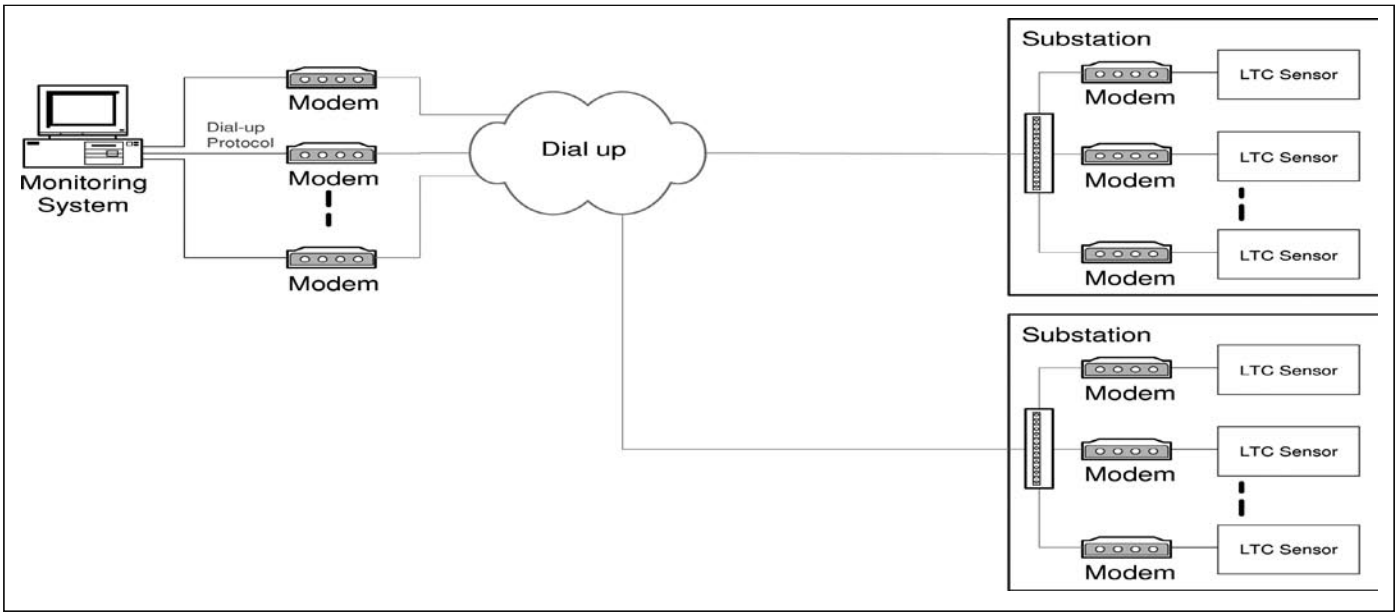


Figure #18: Case #7, System Architecture

## Case Study #7

The following system consists of a LTC monitoring system which communicates via dial-up modems. This system provides monitoring on the transformer and the LTC's condition including monitoring the LTC tap operations, tap operation counts, LTC tap wear factors, the temperature difference between the transformer tank and the LTC compartment, the operational characteristics while operating through the various tap positions (LTC Controls), and monitoring the drive motor current and motor index. The utility using this system now performs condition-based maintenance on their LTCs.

They also have credited this system with averting over 30 failures.

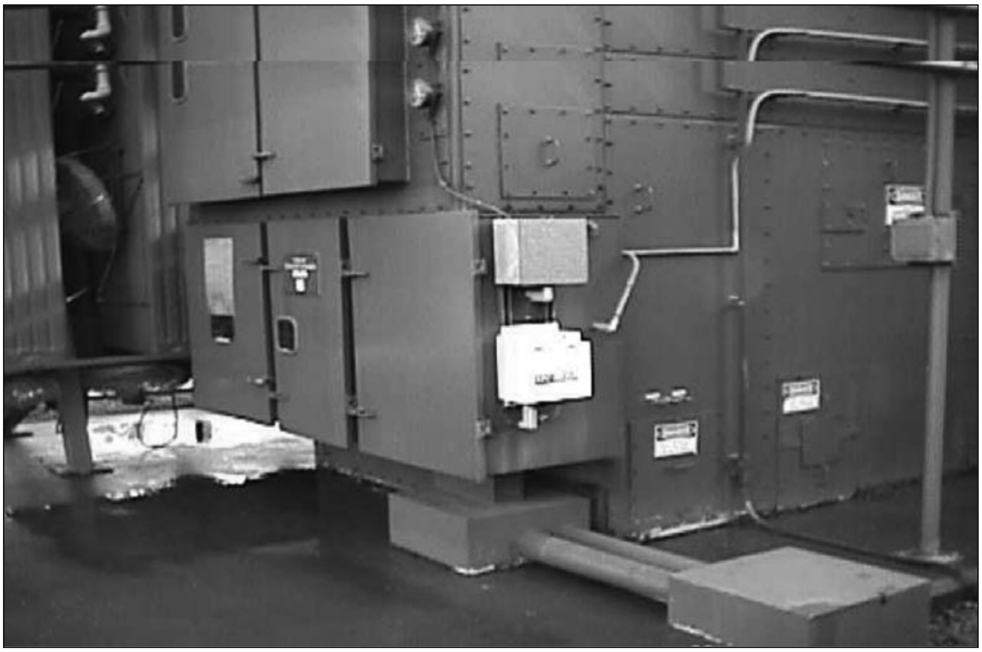


Figure #19: Case #7, LTC Sensor Installation

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Field validation of moisture and bubbling model:

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- D. Pomi, Pacific Gas& Electric Co. "Discoveries of LTC Problems Which Support
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# Protecting Power Transformers From Common Adverse Conditions

**Ali Kazemi, Schweitzer Engineering Laboratories, Inc., Casper Labuschagne, Schweitzer Engineering Laboratories, Inc.**

Abstract — Power transformers of various sizes and configurations are applied throughout the power system. These transformers play an important role in power delivery and in the integrity of the power system network as a whole.

Power transformers have operating limits beyond which transformer loss of life can occur. This paper examines the adverse conditions to which a power transformer might be subjected. Our discussion includes transformer overload, through fault, and overexcitation protection. We discuss each operating condition and its effect on the power transformer, and provide a solution in the protection scheme for each operating condition.

## I. INTRODUCTION

In general, the main concern with transformer protection is protecting the transformer against internal faults and ensuring security of the protection scheme for external faults. System conditions that indirectly affect transformers often receive less emphasis when transformer protection is specified.

Overloading power transformers beyond the nameplate rating can cause a rise in temperature of both transformer oil and windings. If the winding temperature rise exceeds the transformer limits, the insulation will deteriorate and may fail prematurely.

Prolonged thermal heating weakens the insulation over time, resulting in accelerated transformer loss-of-life.

Power system faults external to the transformer zone can cause high levels of current flowing through the transformer.

Through-fault currents create forces within the transformer that can eventually weaken the winding integrity.

A comprehensive transformer protection scheme needs to include protection against transformer overload, through-fault, and overexcitation, as well as protection for internal faults.

This article focuses on liquid-immersed transformers because the majority of medium- and high-voltage transformers are of this type.

## II. POWER TRANSFORMER CAPABILITY LIMITS

A power transformer consists of a set of windings around a magnetic core. The windings are insulated from each other and the core. Operational stresses can cause failure of the transformer winding, insulation, and core.

The power transformer windings and magnetic core are subject to a number of different forces during operation [3]:

- Expansion and contraction caused by thermal cycling.
- Vibration caused by flux in the core changing direction every half cycle.
- Localized heating caused by eddy currents in parts of the winding, induced by magnetic flux.
- Impact forces caused by through-fault currents.
- Thermal heating caused by overloading.

ANSI/IEEE standards [1] [2] provide operating limits for power transformers. Initially, these operating limits only considered the thermal effects of transformer overload. Later, the capability limit was changed to include the mechanical effect of higher fault currents through the transformer. Power transformer through-faults produce physical forces that cause insulation compression, insulation wear, and friction-induced displacement in the winding. These effects are cumulative and should be considered over the life of the transformer.

Table I shows four categories [1] for liquid-immersed power transformers, based on the transformer nameplate rating.

**Table 1: Transformer Categories**

| Category | Single Phase KVA | Three Phase KVA |
|---|---|---|
| I | 5 to 500 | 15 to 500 |
| II | 501 to 1667 | 501 to 5000 |
| III | 1668 to 10000 | 5001 to 30000 |
| IV | Above 10000 | Above 30000 |

To provide a more comprehensive representation of the long-term effects of system conditions on power transformers, each category includes through-fault capability limits which are a function of the maximum current through the transformer.

The maximum current (in per unit [p.u.] of the transformer base rating) is calculated based on the transformer short-circuit impedance for category I and II transformers.

Maximum current calculation for category III and IV transformers is based on the overall impedance of the transformer short-circuit impedance and the system impedance.

## A. Category I Transformers

Fig. 1 shows the through-fault capability limit curve for category I transformers. The curve reflects both thermal and mechanical considerations. For short circuit currents at 25–40 times the base current, the I2t limit of 1250 defines the curve, where I is the symmetrical fault current in multiples of the transformer base current and t is in seconds.

Current (I) is based on the transformer's per-unit short circuit impedance. A transformer with 4 percent impedance will have a maximum short circuit current of 25 p.u. (1/0.04), which results in a time of 2 seconds (1250/252) for its through fault capability limit.

## I TRANSFORMERS

## B. Category II and III Transformers

For Category II and III transformers, the IEEE standard provides an additional through-fault capability limit curve.

The additional curve takes into account the fault frequency that the transformer is subjected to throughout its entire life. In general, use a frequent-fault curve if fault frequency is higher than ten through-faults for category II transformers and higher than five through-faults for category III transformers. Fault frequency is considered over the life of the transformer.

Fig. 2 represents the through-fault capability limit curve for category II and III transformers that experience infrequent faults. The curve is limited to two seconds.

To acknowledge the cumulative nature of damage caused by through-faults, the standard supplements the through-fault capability limit curve to reflect mechanical damage. It calculates the I2t curve based on the actual transformer impedance.

For category II transformers, consider the mechanical duty for fault currents higher than 70 percent of maximum possible short-circuit current. For category III and IV transformers, consider mechanical duty for through-fault currents higher than 50 percent of maximum possible short-circuit current.

Fig. 3 shows the through-fault capability limit curve for a category II transformer with 7 percent impedance. The I2t calculation is at maximum short-circuit current for a time of 2 seconds.

For a transformer with 7 percent impedance, I2t calculates at 408 as shown below:

I = 1/0.07 = 14.29; this is the maximum short-circuit current in p.u. of transformer base rating I2t = (14.29)2 • .2 = 408

The lower portion of the curve is 70 percent of maximum short-circuit current and the I2t calculated above.

I = 0.7 • 14.29 = 10

t = 408/(I)2 = 4.08

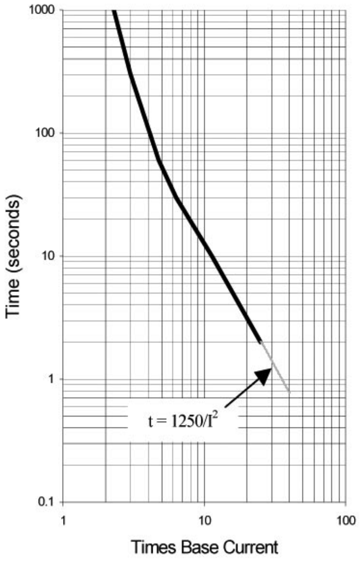


**Fig. 1. Through-Fault Capability limit curve for Liquid-Immersed Category**

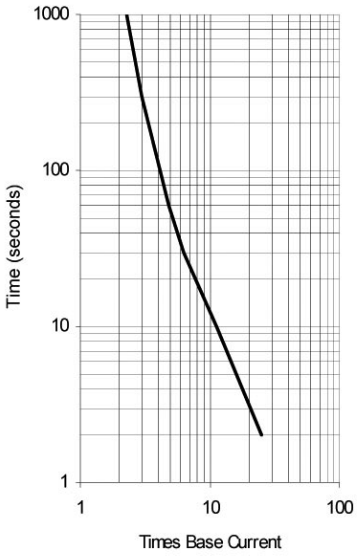


**Fig. 2. Through-Fault Capability Limit Curve for Liquid-Immersed Category II and III Transformers with Infrequent Faults**

### C. Category IV Transformers

Fig. 4 shows the through-fault capability limit curve for category IV transformers. The curve represents both the frequent and the infrequent fault occurrences. For category III and IV transformers, the mechanical duty limit curve starts at 50 percent of the short circuit current.

### D. Protection Considerations

After determining the proper through-fault capability limit curve for a particular transformer, select a time-overcurrent characteristic to coordinate with the through-fault capability limit curve.

In distribution transformer applications where a number of feeders are connected to the low-voltage bus, the feeder relays become the first line of defense. IEEE Standard C37.91 recommends [3] setting the inverse time-overcurrent characteristic of the feeder relays to coordinate with the through-fault capability limit curve of the transformer, as shown in Fig. 5.

Coordinating an overcurrent element with an I2t thermal element requires further consideration. Although the extremely inverse time-overcurrent characteristic of the overcurrent relay seems to emulate the shape of the thermal curve, the coordination is only valid for a fixed initial overcurrent condition [4]. Once an overload or through-fault condition causes the transformer winding temperature to rise, coordination between the overcurrent relay and the thermal element is no longer valid. In this situation, the overcurrent relay does not prevent thermal damage caused by cyclic overloads.

## III. TRANSFORMER OVERLOAD

### A. Overcurrent vs. Overload

For this paper, we define overcurrent as current flowing through the transformer resulting from faults on the power system. Fault currents that do not include ground are generally in excess of four times full-load current; fault currents that include ground can be below the full-load current depending on the system grounding method. Overcurrent conditions are typically short in duration (less than two seconds) because protection relays usually operate to isolate the faults from the power system.

Overload, by contrast, is current drawn by load, a load current in excess of the transformer nameplate rating. IEEE standard [5] lists nine risks when loading large transformers beyond nameplate ratings. In summary, loading large power transformers beyond nameplate ratings can result in reduced dielectric integrity, thermal runaway condition (extreme case) of the contacts of the tap changer, and reduced mechanical strength in insulation of conductors and the transformer structure.

Three factors, namely water, oxygen, and heat, determine the insulation (cellulose) life of a transformer. Filters and other oil preservation systems control the water and oxygen content in the insulation, but heat is essentially a function of the

**Fig. 4. Through-Fault Capability Limit Curve for Liquid-Immersed Category IV Transformers**

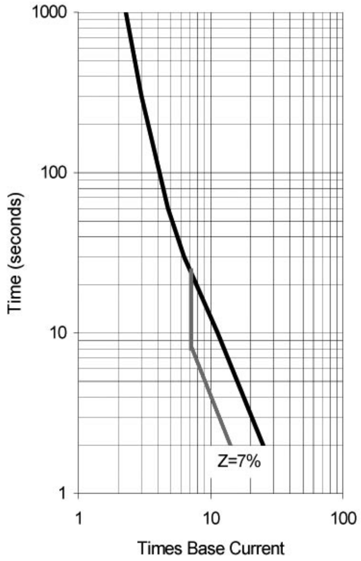
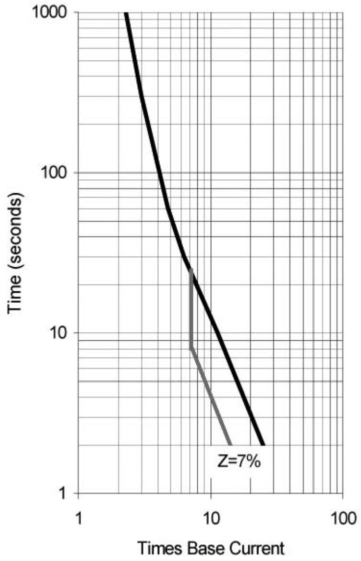


**Fig. 5. TOC Coordination with Category IV Transformer Through-Fault Capability Limit Curve**



ambient temperature and the load current. Current increases the hottest-spot temperature (and the oil temperature), and thereby decreases the insulation life span.

Equation (1) is used as an indication of the insulation-aging effect of overloading a transformer.

$$\%LOL = \frac{H}{ILIFE} \bullet 100 \qquad (1)$$

where:
%LOL percentage loss-of-life
H = Time in hours
ILIFE = Insulation life

In general, assume the insulation life of a transformer to be 180,000 hours and the rated hottest-spot temperature to be

110ºC. Therefore, a transformer operating at the rated hottestspot temperature of 110ºC for 24 hours ages at a rate of 0.0133 percent, calculated as follows:

$$\%LOL = \frac{24 \cdot 100}{180{,}000} = 0.01333\%$$

However, overloading the transformer decreases the insulation life span exponentially. To relate the hottest-spot temperature to the per-unit insulation life, we calculate FAA, the Aging Acceleration Factor. Equation (2) shows the calculation for FAA, with 15,000 being a design constant.

$$FAA = \exp^{\left[\frac{15{,}000}{383} - \frac{15{,}000}{\theta_H + 273}\right]} \qquad (2)$$

where:
$\theta_H$ is the calculated hottest-spot temperature

An FAA factor of 10 means that, at the present hottest-spot temperature, the transformer insulation ages 10 times faster than the per-unit life over a given time interval. In terms of temperature, an FAA of 10 corresponds to a hottest-spot temperature of approximately 135ºC.

## B. Ambient Temperature

Excessive load current alone may not result in damage to the transformer if the absolute temperature of the windings and transformer oil remains within specified limits. Transformer ratings are based on a 24-hour average ambient temperature of 30˚C (86˚F). Note that the ambient temperature is the air in contact with the radiators or heat exchangers.

Table II shows the increase or decrease from rated kVA for other than average daily ambient temperature of 30˚C.

TABLE II
TRANSFORMER LOADING WITH TEMPERATURE AS A FACTOR

| Type of cooling | Percentage of kVA rating | |
|---|---|---|
| | Decrease load for each °C higher than 30°C | Increase load for each °C lower than 30°C |
| Self-cooled (OA) | 1.5 | 1.0 |
| Water-cooled (OW) | 1.5 | 1.0 |
| Forced-air cooled (OA/FA, OA/FA/FA) | 1.0 | 0.75 |
| Forced-oil, -air, -water, -cooled (FOA, FOW, and OA/FOA/FOA) | 1.0 | 0.75 |

## C. Thermal Models Including Ambient Temperature

More sophisticated transformer thermal models [5] use load current as well as the ambient temperature to calculate Top-Oil temperature and hottest-spot temperature.

To calculate the absolute Top-Oil temperature and hottest-spot temperature, the model adds the calculated Top-Oil and hottest-spot temperatures to the measured ambient temperature (subtract for a temperature drop). When the ambient temperature is not available, or communication with the device that supplies the ambient temperature information is lost, the thermal model uses a fixed value as reference for the ambient temperature. However, using a fixed value instead of the actual ambient temperature as reference means that the model cannot indicate whether actual damage will occur at any particular level of overload.

## D. Thermal Models Excluding Ambient Temperature

Although less accurate, models without direct ambient temperature can still provide useful information as to the temperature rise of the transformer oil when constant current flows.

These models project the temperature rise within the transformer as a function of (constant) load current flowing though the transformer. For example, looking at the manufacturer's literature, we see that a hypothetical transformer has a time constant (TC) of one hour. Using Equation (3), we calculate that the transformer will reach steady-state temperature after five hours (five time constants) when constant full-load current flows.

$$\theta(t) = I_{FL}\left(1 - e^{\frac{-t}{TC}}\right) \qquad (3)$$

where:
$\theta$ = Transformer oil temperature
$I_{FL}$ = Transformer full-load current
TC = Time constant
t = Time in seconds

Furthermore, we can calculate that, if full-load current flows for one hour, the temperature is approximately 63 percent of the final value (solid curve in Fig. 6). However, we see that if we overload the transformer by 20 percent, the temperature is approximately 75 percent of the final value after one hour (dashed curve in Fig. 6).

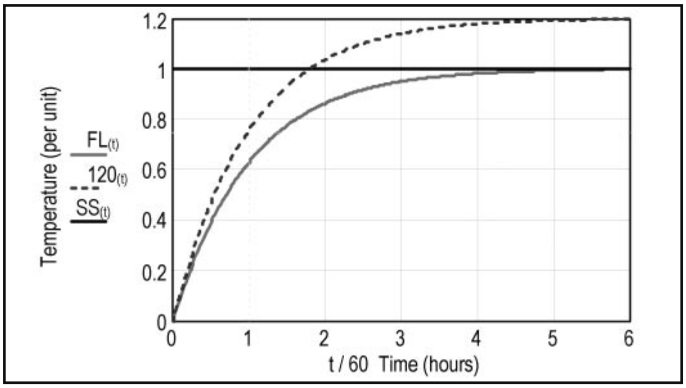


Fig. 6. Oil Temperature Curves For Full-Load Current and Twenty Percent Overload Current

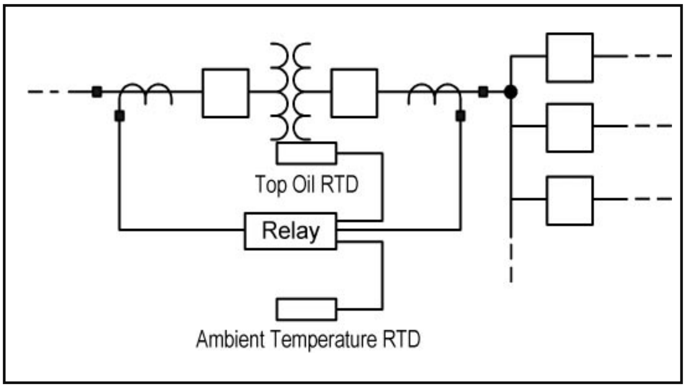


Fig. 7. Transformer Protection Relay With Connected RTDs for Thermal Monitoring

We now use this information (75 percent) as a warning signal that we are overloading the transformer. Because we do not measure the ambient temperature, we cannot determine whether actual damage will occur at this level of overload.

### E. Cooling System Efficiency

Many installations provide remote thermal devices (RTDs) for both ambient temperature and oil temperature measurement.

Measuring both ambient temperature and oil temperature provides a method for comparing calculated oil-temperature values to measured oil-temperature values. Ideally, calculated oil-temperature values and measured oil-temperature values should be the same. Differences between calculated and measured values can indicate that the cooling system is not performing at full efficiency, resulting from such problems as defective fan motors. At first installations, a practical approach is to use the difference between calculated and measured values to fine-tune setting of transformer constants.

Because transformer constants are not always available at the time of commissioning, some constants may have been assumed during the setting process. Once we establish that the cooling system is in good working order, we can assume that the difference between calculated and measured values is the result of incorrect transformer constant settings. After adjusting the transformer constants to the point where calculated and measured values are the same, we can now attribute any subsequent deviations in calculated and measured values can now be attributed to lower efficiency of the cooling system.

### F. Thermal Protection Application Example

The idea behind a thermal element is to provide the system operator with meaningful data about the state of the transformer.

The thermal element provides data for determining whether a transformer can withstand further short-term or long-term overloads without sacrificing transformer loss-of-life.

This information is a function of the ambient temperature, transformer-loading history, present loading condition, and cooling system efficiency.

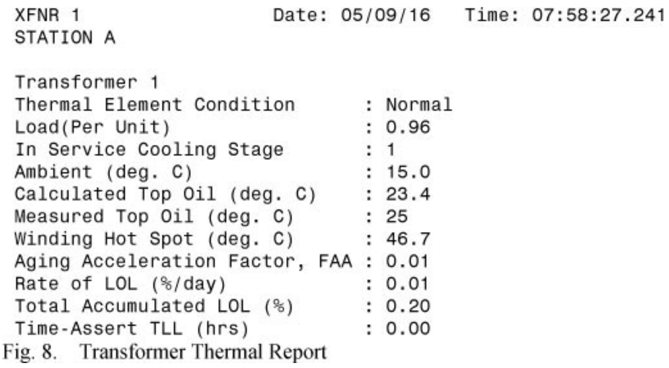
The inputs to the transformer thermal monitor include transformer Top-Oil temperature, ambient temperature, and transformer loading indication provided through either the high-side or the low-side current transformers.

Fig. 7 shows a one-line diagram for a transformer protection relay providing differential protection and thermal monitoring for the transformer. RTDs provide Top Oil and ambient temperatures to the relay.

The thermal element provides the transformer thermal status both as alarm points and as a report. The alarm points indicate whether a measured value exceeds a settable threshold.

These alarm points might include Top-Oil Temperature, Hot-test-spot Temperature, Aging Acceleration Factor, Daily Rate of Loss-of-Life, and Total Loss-of-Life.

The thermal element report is shown in Fig. 8.



```
XFNR 1                 Date: 05/09/16   Time: 07:58:27.241
STATION A

Transformer 1
Thermal Element Condition       : Normal
Load(Per Unit)                  : 0.96
In Service Cooling Stage        : 1
Ambient (deg. C)                : 15.0
Calculated Top Oil (deg. C)     : 23.4
Measured Top Oil (deg. C)       : 25
Winding Hot Spot (deg. C)       : 46.7
Aging Acceleration Factor, FAA  : 0.01
Rate of LOL (%/day)             : 0.01
Total Accumulated LOL (%)       : 0.20
Time-Assert TLL (hrs)           : 0.00
```

Fig. 8. Transformer Thermal Report

Fig. 8. Transformer Thermal Report

## IV. THROUGH-FAULT MONITORING

As discussed previously, through-fault current produces both thermal and mechanical effects than can be damaging to the power transformer. The mechanical effects, such as winding compression and insulation wear, are cumulative. The extent of damage from through-faults is a function of the current magnitude, fault duration, and total number of fault occurrences.

Power transformers throughout the power system experience different levels of through-fault current in terms of magnitude, duration, and frequency. The recording capability of some transformer protection relays allows for monitoring and recording of the through-fault current. The relay records the cumulative I2t value for each phase and compares it against a threshold to provide an alarm. Fig. 9 shows the logic diagram for the cumulative through-fault logic.

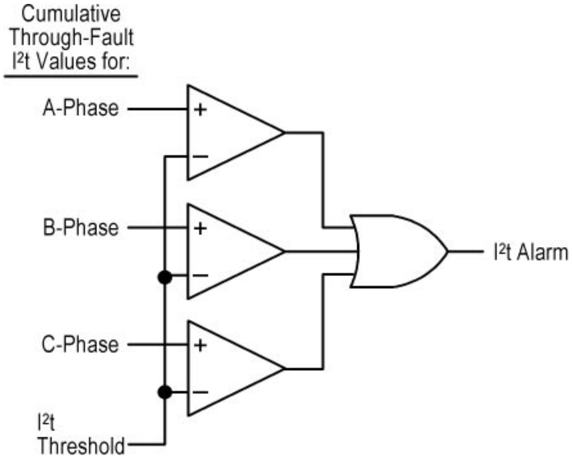
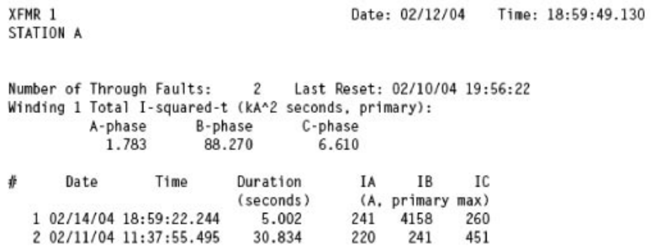


Fig. 9. Cumulative Through-Fault Logic

The recorded values assist the maintenance crew in prioritizing and scheduling transformer maintenance and testing. Over time, the recorded values also provide additional information in determining problems (winding insulation failure, insulation compression, loose winding, etc.) with the power transformer.

Excessive through-fault occurrences within a given period can also indicate the need for maintenance such as tree trimming and right of way clearance [8].

Fig. 10 shows the through-fault report for a transformer. The report provides the total I2t value for each phase. The report also provides the date, time, duration, and maximum current through the transformer for each occurrence.



```
XFMR 1                                   Date: 02/12/04    Time: 18:59:49.130
STATION A


Number of Through Faults:     2    Last Reset: 02/10/04 19:56:22
Winding 1 Total I-squared-t (kA^2 seconds, primary):
          A-phase      B-phase      C-phase
            1.783       88.270        6.610

#      Date       Time       Duration      IA     IB     IC
                             (seconds)     (A, primary max)
   1 02/14/04 18:59:22.244     5.002      241   4158    260
   2 02/11/04 11:37:55.495    30.834      220    241    451
```

Fig. 10. Transformer Through-Fault Report

## V. TRANSFORMER OVEREXCITATION

The flux in the transformer core is directly proportional to the applied voltage and inversely proportional to the frequency.

Overexcitation can occur when the per-unit ratio of voltage to frequency (Volts/Hz) exceeds 1.05 p.u. at full load and 1.10 p.u. at no load. An increase in transformer terminal voltage or a decrease in frequency will result in an increase in the flux.

Overexcitation results in excess flux, which causes transformer heating and increases exciting current, noise, and vibration.

Some of the possible causes of overexcitation are:

- Problems with generator excitation system
- Operator error
- Sudden loss-of-load
- Unloaded long transmission lines

### A. Transformer Differential Relay and Overexcitation

Saturation of the power transformer core caused by overexcitation results in the flow of excitation current. In an extreme case, the increase in excitation current can cause the transformer differential relay to operate. Because the characteristic of the transformer differential relay does not correlate to the transformer overexcitation limit curve, it is impractical to depend on transformer differential protection to provide overexcitation protection. Furthermore, operation of the transformer differential relay for an overexcitation condition, which is a system phenomenon, can lead fault investigators to start their investigation at the transformer instead of looking for system disturbances. Use a Volts/Hz element to provide overexcitation protection. Under overexcitation conditions, block or restrain the differential element to prevent false operations.

If a Volts/Hz element is not available, use the harmonic content of the excitation current to determine the degree of overexcitation of the transformer core. Table III shows typical harmonic content of the excitation current.

The excitation current consists mainly of odd harmonics, with the third harmonic being the predominant harmonic. The third harmonic is a triplen harmonic [9]. Delta-connected transformer windings (power or current transformers) filter out triplen harmonics (3, 9, 15, etc.). Since the next highest harmonic is the fifth harmonic, most transformer differential relays use the fifth harmonic to detect overexcitation conditions.

In applications where the power transformer might be overexcited, block the differential element from operating on transformer exciting current.

TABLE III.
TRANSFORMER EXCITATION CURRENT AND HARMONICS

| Frequency | Magnitude (primary amps) | % of Nominal |
|---|---|---|
| Fundamental | 22.5 | 52.0 |
| Third | 11.1 | 26.0 |
| Fifth | 4.9 | 11.0 |
| Seventh | 1.8 | 4.0 |

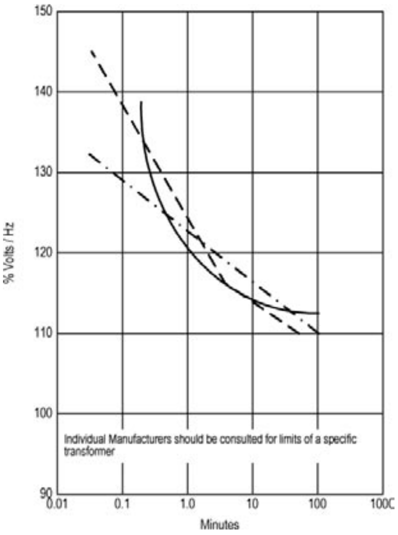


**Fig. 11. Typical Transformer Overexcitation Limit Curves**

### B. Overexcitation Protection

Obtain the overexcitation limit for a particular transformer through the transformer manufacturer. The overexcitation limit is either a curve or a set point with a time delay. Fig. 11 shows typical overexcitation limit curves for different transformers.

Provide overexcitation protection for power transformers through a Volts/Hz element that calculates the ratio of the measured voltage to frequency in p.u. of the nominal quantities.

In applications that provide overexcitation protection for a generator step-up (GSU) transformer, consider the overexcitation limits of both the GSU and the generator. Then set the overexcitation element to coordinate with the limit curves of both the GSU and the generator. Fig. 12 shows the coordination of the overexcitation element with the generator and the GSU limit curves. Use a composite limit curve to achieve proper coordination.

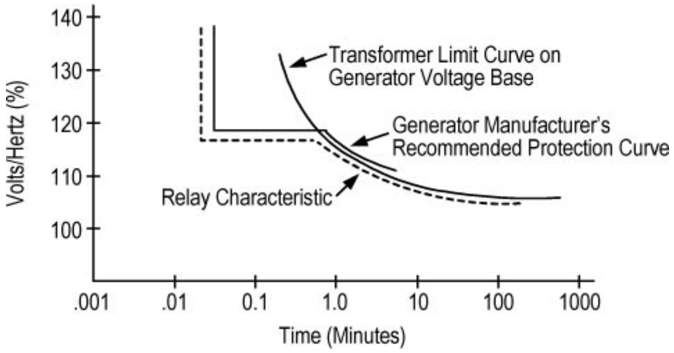


**Fig. 12. Overexcitation Protection Coordination Curve**

## VI. CONCLUSION

Power transformers play a significant role in power system delivery. Proper application of relay elements that monitor a transformer's thermal state and through-faults can provide both short and long term benefits. These benefits include:

- Transformer overload protection, including cyclic overloads
- Continuous transformer thermal status indication that allows the system operator to make transformer loading decisions based on transformer thermal state
- Cooling system efficiency indication
- Records of cumulative per phase I2t values as seen by the transformer
- Settable I2t alarm thresholds that can notify the system operator of excessive through-fault current seen by the transformer
- Cumulative I2t values as a measure to prioritize transformer maintenance

Overexcitation is a system condition and is not limited to generating stations. Proper application of Volts/Hz elements can prevent damage to transformers resulting from system overvoltage or underfrequency conditions.

## VII. REFERENCES

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# Transformer Maintenance

## Department of the Interior, the Bureau of Reclamation

### Dry type Transformer Maintenance Summary

**When new after energizing and allowing temperature and loading to stabilize:**

- Do an infrared scan and compare with temperature gage, if any.
- If transformer is gas filled (nitrogen [$N_2$]), check pressure gage against data sheets; never allow gas pressure to fall below 1 pound per square inch (psi).
- Check loading and compare with nameplate rating.
- Functionally test fans and controls for proper operation.
- Functionally test temperature alarms and annunciator points.
- Check area around transformer clear of debris and parts storage.
- Check transformer room for proper ventilation.

**After 1 week of operation at normal loading:**

- Perform infrared scan and compare with temperature gage, if any.
- Check temperature gage, if any, and compare with nameplate rating.
- Check loading and compare with nameplate rating.

**Annually** ***(Note: The time between these periodic inspections may be increased if the first internal inspection of windings and connections are found clean and in good condition and if loading is at or below nameplate rating.):***

- Perform an infrared scan before de-energizing.
- De-energize and remove panels for internal inspection.
- Use vacuum to remove as much dirt as possible.
- After vacuuming, use low pressure dry air (20 to 25 psi) to blow off remaining dirt. Caution: Make sure air is dry.
- Check for discolored copper and discolored insulation.
- Check for corroded and loose connections.
- Check for carbon tracking on insulation and insulators.
- Check for cracked, chipped, and loose insulators.
- If windings are found dirty, add filter material to air intake ports.
- Check fan blades for cleanliness; remove dirt and dust.
- Check fans, controls, alarms and annunciator points.
- Check pressure gage on N2 filled transformers; compare with weekly data sheets; never allow pressure to fall below 1 psi.
- Repair all problems found in above inspections.

### INTRODUCTION TO RECLAMATION TRANSFORMERS

Transformers rated 500 kilovoltamperes (kVA) and above are considered power transformers.

All generator step-up (GSU) transformers, and many station service, and excitation transformers are considered power transformers because they are rated 500 kVA or larger.

Standards organizations such as American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) consider average GSU transformer life to be 20 to 25 years. This estimate is based on continuous operation at rated load and service conditions with an average ambient temperature of 40°C (104 °F) and a temperature rise of 65°C. This estimate is also based on the assumption that transformers receive adequate maintenance over their service life [24].

The Bureau of Reclamation, Bonneville Power Administration, and Western Area Power Administration conduct regular studies to determine statistical equipment life. These studies show that average life of a Reclamation transformer is 40 years. Reclamation gets longer service than IEEE estimates because we operate at lower ambient temperatures and with lower loads. A significant number of transformers were purchased in the 1940s, 1950s, and into the 1970s. Several have been replaced, but we have many that are nearing, or are already well past, their anticipated service life. We should expect transformer replacement and failures to increase due to this age factor.

Current minimum replacement time is around 14 months; a more realistic time may be 18 months to 2 years. In the future, lead times may extend well beyond what they are today. Therefore, high quality maintenance and accurate diagnostics are important for all transformers, but absolutely essential for older ones — especially for critical transformers that would cause loss of generation. It is also very important to consider providing spares for critical transformers.

### 3. TRANSFORMER COOLING METHODS

Heat is one of the most common destroyers of transformers. Operation at only 10°C above the transformer rating will cut transformer life by 50%. Heat is caused by internal losses due to loading, high ambient temperature, and solar radiation. It is important to understand how your particular transformers are cooled and how to detect problems in the cooling systems. ANSI and IEEE require the cooling class of each transformer to appear on its nameplate. Cooling classifications, with short explanations, appear in sections 3.1 and 3.2.

The letters of the class designate inside atmosphere and type or types of cooling. In some transformers, more than one class of cooling and load rating are indicated. At each step of additional cooling, the rating increases to correspond with increased cooling. Note that the letter "A" indicates air, "FA" indicates forced air (fans), "O" indicates oil, "FO" indicates forced oil (pumps), "G" indicates some type of gas, and "W" indicates there is a water/oil heat exchanger.

### 3.1 Dry Type Transformers

Cooling classes of dry type transformers are covered by ANSI/IEEE standard C57.12.01 Section 5.1 [1]. A short explanation of each class is given below.

1. Class AA are ventilated, self-cooled transformers. This means that there are ventilation ports located in outside walls of the transformer enclosure. There are no fans to force air into and out of the enclosure with typically no external fins or radiators. Cooler air enters the lower ports, is heated as it rises past windings, and exits the upper ventilation ports. (It will not be repeated below; but it is obvious that in every cooling class, some heat is also removed by natural circulation of air around the outside of the enclosure.)

2. Class AFA transformers are self-cooled (A) and additionally cooled by forced circulation of air (FA). This means that there are ventilation ports for fan inlets and outlets only. (Inlets are usually filtered.) Normally, there are no additional ventilation ports for natural air circulation.

3. Class AA/FA transformers are ventilated, self-cooled (same as Class AA in item 1). In addition, they have a fan or fans providing additional forced-air cooling. Fans may be wired to start automatically when the temperature reaches a pre-set value. These transformers generally have a dual load rating, one for AA (self-cooling natural air flow) and a larger load rating for FA (forced air flow).

4. Class ANV transformers are self-cooled (A), non-ventilated (NV) units. The enclosure has no ventilation ports or fans and is not sealed to exclude migration of outside air, but there are no provisions to intentionally allow outside air to enter and exit. Cooling is by natural circulation of air around the enclosure. This transformer may have some type of fins attached outside the enclosure to increase surface area for additional cooling.

5. Class GA transformers are sealed with a gas inside (G) and are self-cooled (A). The enclosure is hermetically sealed to prevent leakage. These transformers typically have a gas, such as nitrogen or freon, to provide high dielectric and good heat removal. Cooling occurs by natural circulation of air around the outside of the enclosure. There are no fans to circulate cooling air; however, there may be fins attached to the outside to aid in cooling.

#### 3.1.1 Potential Problems and Remedial Actions for Dry Type Transformer Cooling Systems [14].

It is important to keep transformer enclosures reasonably clean. It is also important to keep the area around them clear. Any items near or against the transformer impede heat transfer to cooling air around the enclosure. As dirt accumulates on cooling surfaces, it becomes more and more difficult for air around the transformer to remove heat. As a result, over time, the transformer temperature slowly rises unnoticed, reducing service life.

Transformer rooms and vaults should be ventilated. Portable fans (never water) may be used for additional cooling if necessary. A fan rated at about 100 cubic feet per minute (cfm) per kilowatt (kW) of transformer loss [5], located near the top of the room to remove hot air, will suffice. These rooms/vaults should not be used as storage.

When the transformer is new, check the fans and all controls for proper operation. After it has been energized and the loading and temperature are stable, check the temperature with an infrared (IR) camera and compare loading with the nameplate. Repeat the temperature checks after 1 week of operation.

Once each year under normal load, check transformer temperatures with an IR camera [4,7]. If the temperature rise (above ambient) is near or above nameplate rating, check for overloading. Check the temperature alarm for proper operation. Check enclosures and vaults/rooms for dirt accumulation on transformer surfaces and debris near or against enclosures. Remove all items near enough to affect air circulation. To avoid dust clouds, a vacuum should first be used to remove excess dirt. Low pressure (20 to 25 pounds per square inch [psi]) dry compressed air may be used for cleaning after most dirt has been removed by vacuum. The transformer must be de-energized before this procedure unless it is totally enclosed and there are no exposed energized conductors. Portable generators may be used for lighting.

After de-energizing the transformer, remove access panels and inspect windings for dirt- and heat-discolored insulation and structure problems [14]. It is important that dirt not be allowed to accumulate on windings because it impedes heat removal and reduces winding life. A vacuum should be used for the initial winding cleaning, followed by compressed air [7]. Care must be taken to ensure the compressed air is dry to avoid blowing moisture into windings. Air pressure should not be greater than 20 to 25 psi to avoid imbedding small particles into insulation. After cleaning, look for discolored copper and insulation, which indicates overheating. If discoloration is found, check for loose connections. If there are no loose connections, check the cooling paths very carefully and check for overloading after the transformer has been re-energized. Look for carbon tracking and cracked, chipped, or loose insulators. Look for and repair loose clamps, coil spacers, deteriorated barriers, and corroded or loose connections.

Check fans for proper operation including controls, temperature switches, and alarms. Clean fan blades and filters if needed. A dirty fan blade or filter reduces cooling air flow over the windings and reduces service life. If ventilation ports do not have filters, they may be fabricated from home-furnace filter material. Adding filters is only necessary if the windings are dirty upon yearly inspections.

## OIL-FILLED TRANSFORMER MAINTENANCE SUMMARY

| Task | After 1 Month of Service | Annually | 3 to 5 Years |
|---|---|---|---|
| Before energizing, inspect and test all controls, wiring, fans alarms, and gages. | | | |
| Indepth inspection of transformer and cooling system, check for leaks and proper operation.<br>Do a DGA. | Oil pumps load current, oil flow indicators, fans, etc. See 3.2.5, 3.2.6, and 4.1.<br>Thermometers 4.1.2 and 3.<br>Heat exchangers.<br>Transformer tank 4.1.1.<br>Oil level gages 4.1.4.<br>Pressure relief 4.1.5.<br>Do a DGA. | Oil pumps load current, oil flow indicators, fans etc, see 3.2.5, 3.2.6 and 4.1<br>Thermometers 4.1.2 and 3,<br>heat exchangers<br>Transformer tank 4.1.1<br>Oil level gages 4.1.4<br>Pressure relief 4.1.5<br>Do a DGA | Check diaphragm or bladder for leaks if you have conservator. See 4.2.2. |
| IR scan of transformer cooling system, bushings and all wiring. | See 3.2.5 and 4.1.8. | See 3.2.5 and 4.1.8. | |
| Test all controls, relays, gages; test alarms and annunciator points. | See 3.2.5, 4.1.4, 4.1.5. | See 3.2.5<br>Inspect pressure relief for leaks and indication for operation (rod extension) see 4.1.5 | Thermometers. See 4.1.3.<br>Oil level gages 4.1.4.<br>Inspect pressure relief 4.1.5.<br>Sudden pressure relay 4.1.6.<br>Buchholz relay 4.1.7.<br>Test alarms, fan and pump controls, etc. See 3.2.6. |
| Inspect transformer bushings. | Check with binoculars for cracks and chips; look for oil leaks and check oil levels.<br>IR scan. See 4.1.8. | check with binoculars for cracks and chips, look carefully for oil leaks and check oil levels IR Scan See 4.1.8 | |
| Indepth inspection of bushings, cleaning waxing if needed. | | | Close physical inspection, cleaning/ waxing, and Doble testing, plus checks in boxes above left. See 4.1.8. |
| Doble test transformer and bushings. | Doble test transformer and bushings before energizing. See 4.1.8, 4.7. | | See 4.1.8 and 4.7. |
| Inspect pressure controls if you have a nitrogen over oil transformer.<br>Inspect pressure gage. | See 4.2.2. | See 4.2.2.<br>Also see 4.2.1 to test pressure gage if trans has $N_2$ over oil with no means to automatically add $N_2$. | |

Check pressure gauges by looking at the weekly data sheets; if pressure never varies with temperature changes, the gauge is defective. Never allow the pressure to go below about 1 psi during cold weather. Add nitrogen to bring the pressure up to 2 1/2 to 3 psi to insure that moist air will not be pulled in.

### 3.2 Liquid-Immersed Transformers

Cooling classes of liquid-immersed transformers are covered by IEEE C57.12.00 Section 5.1 [2]. A short explanation of each class follows:

3.2.1 Liquid-Immersed, Air-Cooled. There are three classes in this category.

1. Class OA: Oil-immersed, self-cooled. Transformer windings and core are immersed in some type of oil and are self-cooled by natural circulation of air around the outside enclosure. Fins or radiators may be attached to the enclosure to aid in cooling.

2. Class OA/FA: Liquid-immersed, self-cooled/forced air-cooled. Same as OA above, with the addition of fans. Fans are usually mounted on radiators. The transformer typically has two load ratings, one with the fans off (OA) and a larger rating with fans operating (FA). Fans may be wired to start automatically at a pre-set temperature.

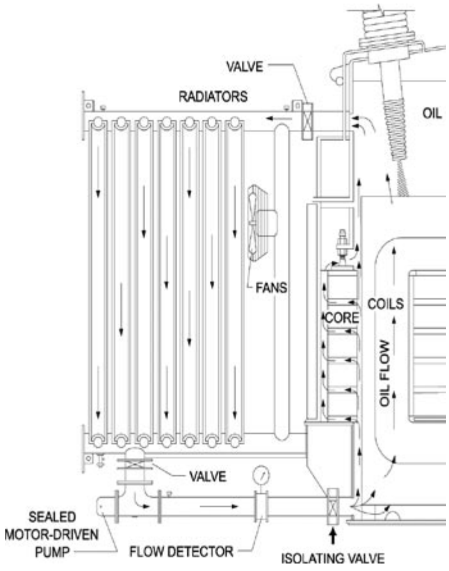


**Figure 1. — Typical Oil Flow.**

3. Class OA/FA/FA: Liquid-immersed, self-cooled/forced air-cooled/forced air-cooled.

Same as OA/FA above with an additional set of fans.

There typically will be three load ratings corresponding to each increment of cooling.

Increased ratings are obtained by increasing cooling air over portions of the cooling surfaces. Typically, there are radiators attached to the tank to aid in cooling.

The two groups of fans may be wired to start automatically at pre-set levels as temperature increases. There are no oil pumps. Oil flow through the transformer windings is by the natural principle of convection (heat rising).

### 3.2.2 Liquid-Immersed, Air-Cooled/Forced Liquid-Cooled. There are two classes in this group.

1. Class OA/FA/FOA: Liquid-immersed, self-cooled/forced air-cooled/forced liquid, and forced air-cooled. Windings and core are immersed in some type of oil. This transformer typically has radiators attached to the enclosure. The transformer has self-cooling (OA) natural ventilation, forced air-cooling FA (fans), and forced oil-cooling (pumps) with additional forced air-cooling (FOA) (more fans). The transformer has three load ratings corresponding to each cooling step. Fans and pumps may be wired to start automatically at pre-set levels as temperature increases.

2. Class OA/FOA/FOA: Liquid-immersed, self-cooled/forced oil, and forced air-cooled/forced oil, and forced air-cooled. Cooling controls are arranged to start only part of the oil pumps and part of the fans for the first load rating/temperature increase, and the remaining pumps and fans for the second load rating increase. The nameplate will show at least three load ratings.

### 3.2.3 Liquid-Immersed, Water-Cooled. This category has two classes.

1. Class OW: Transformer coil and core are immersed in oil. Typically an oil/water heat exchanger (radiator) is attached to the outside of the tank. Cooling water is pumped through the heat exchanger, but the oil flows only by natural circulation. As oil is heated by the windings, it rises to the top and exits through piping to the radiator. As it is cooled, the oil descends through the radiator and re-enters the transformer tank at the bottom.

2. Class OW/A: Transformer coil and core are immersed in oil. This transformer has two ratings. Cooling for one rating (OW) is obtained as in 1 above. The self-cooled rating (A) is obtained by natural circulation of air over the tank and cooling surfaces.

### 3.2.4 Liquid-Immersed, Forced Liquid-Cooled. This category has two classes.

1. Class FOA: Liquid-immersed, forced liquid-cooled with forced air-cooled. This transformer normally has only one rating. The transformer is cooled by pumping oil (forced oil) through a radiator normally attached to the outside of the tank. Also, air is forced by fans over the cooling surface.

2. Class FOW: Liquid-immersed, forced liquid-cooled, water cooled. This transformer is cooled by an oil/water heat exchanger normally mounted separately from the tank. Both the transformer oil and the cooling water are pumped (forced) through the heat exchanger to accomplish cooling.

### 3.2.5 Potential Problems and Remedial Actions for Liquid Filled Transformer Cooling Systems.

Leaks. Tanks and radiators may develop oil leaks, especially at connections. To repair a leak in a radiator core, you must remove the radiator. Small leaks may also develop in headers or individual pipes. These small leaks possibly may be stopped by peening with a ball peen hammer. Some manufacturer's field personnel try to stop leaks by using a two-part epoxy while the transformer is under vacuum. Do not try this unless the transformer has been drained, because a vacuum may cause bubbles to form in the oil that can lodge in the winding and cause arcing. When all else fails, the leak may be welded with oil still in the radiator, if proper precautions are carefully observed [3, 4].

Welding with oil inside will cause gases to form in the oil. Take an oil sample for a dissolved gas analysis (DGA) before welding and 24 hours after re-energizing to identify gas increases due to welding. If the leak is bad enough, the tank may have to be drained so the leak can be repaired. Treat leaks carefully; do not ignore them. Oil leaks are serious maintenance and environmental issues and should be corrected. Radiators may need to be cleaned in areas where deposits appear on pipes and headers. Dirt and deposits hamper heat transfer to the cooling air. Finned radiators must be cleaned with compressed air when they become dirty.

**Plugs.** After one month of service and yearly, perform an IR scan and physical inspection of radiators and transformer tanks [4,7]. Partially plugged radiators will be cooler than those performing normally. You may also feel the radiator pipes by hand. Plugged radiator sections or individual pipes/plenums will be noticeably cooler; however, you will not be able to reach all of them. Radiators may become plugged with sludge or foreign debris; this usually occurs in water tubes on the oil/water heat exchanger. Do not forget to check the bleed line for two-walled heat exchangers.

If plugged radiators are discovered, they need to be corrected as soon as possible. Some radiators are attached to the main tank with flanges and have isolating valves. These may be removed for cleaning and/or leak repair without draining oil from the transformer. If radiators are attached directly to the main tank, oil must be drained before cleaning them. If radiators are plugged with sludge, chances are the transformer is sludged up also. In this case, the oil should be reprocessed and the transformer cleaned internally. Competent contractors should be obtained if this is necessary.

**Sludge**. If temperature seems to be slowly increasing while the transformer is operating under the same load, check the DGA for moisture, oxygen, and the interfacial tension (IFT). The combination of oxygen and moisture causes sludging, which may be revealed by a low IFT number. Sludge will slowly build up on windings and core, and the temperature will increase over time.

**Valve Problems.** If your transformer has isolating valves for radiators, check to make sure they are fully open on both top and bottom of the radiators. A broken valve stem may cause the valve to be fully or partially closed, but it will appear that the valve is open.

**Mineral Deposits.** Don't even think about spraying water on the radiators or tank to increase cooling except in the most dire emergency. Minerals in the water will deposit on radiators as water evaporates and are almost impossible to remove. These minerals will reduce the efficiency of cooling still further. Additional fans blowing on radiators and/or transformer tanks is a better alternative [4].

One IR scan performed on a transformer running at higher than normal temperature revealed that the oil level was below the upper radiator inlet pipe, which prevented oil circulation. The oil level indicator was defective and stuck on normal. These indicators must be tested.

3.2.6 Cooling System Inspections.

After 1 month of service and yearly, inspect and test the fans. Look at the fans anytime you are around transformers in the switchyard or in the power plant. If it is a hot day and transformers are loaded, all the fans should be running. If a fan is stopped and the rest of the group is running, the inactive fan should be repaired. During an inspection, the temperature controller should be adjusted to start all the fans. Listen for unusual noises from fan bearings and loose blades and repair or replace faulty fans. Bad bearings can also be detected with an IR scan if the fans are running.

After one month of service and yearly, inspect and test the oil pumps.

Inspect piping and connections for leaks. Override the temperature controller so that the pump starts. Check the oil pump motor current on all three phases with an accurate ammeter; this will give an indication if oil flow is correct and if unusual wear is causing additional motor loading. Record this information for later comparison, especially if there is no oil flow indicator. If the motor load current is low, something is causing low oil flow. Carefully inspect all valves to make sure they are fully open. A valve stem may break and leave the valve partially or fully closed, even though the valve handle indicates the valve is fully open. Pump impellers have been found loose on the shaft, reducing oil flow. Sludge buildup or debris in lines can also cause low oil flow. If motor load current is high, this may indicate impeded pump rotation. Listen for unusual noises. Thrust bearing wear results in the impeller advancing on the housing. An impeller touching the housing makes a rubbing sound which is different from the sound of a failing motor bearing. If this is heard, remove the pump motor from the housing and check impeller clearance. Replace the thrust bearing if needed, and replace the motor bearings if the shaft has too much play or if noise is unusual.

Three phase pumps will run and pump some oil even when they are running backwards. Vane type oil-flow meters will indicate flow on this low amount. The best indication of this is that sometimes the pump will be very noisy. The motor load current may also be lower than for full load. If this is suspected due to the extra noise and higher transformer temperature, the pump should be checked for proper rotation. Reverse two phase leads if this is encountered.[4]

After 1 month of service and yearly, check the oil flow indicator. It has a small paddle which extends into the oil stream and may be either on the suction or discharge side of the pump. A low flow of only about 5 feet per second velocity causes the flag to rotate. Flow can be too low, and the indicator will still show flow. If there is no flow, a spring returns the flag to the off position and a switch provides an alarm. With control power on the switch, open the pump circuit at the motor starter and make sure the correct alarm point activates when the pump stops. Check that the pointer is in the right position when the pump is off and when it is running. Pointers can stick and fail to provide an alarm when needed. Oil flow may also be checked with an ultrasonic flow meter. Ultrasonic listening devices can detect worn bearings, rubbing impellers, and other unusual noises from oil pumps.

Pumps can pull air in through gaskets on the suction side of the pumps. The suction (vacuum) on the intake side of the pump can pull air through gaskets that are not tight. Pump suction has also been known to pull air through packing around valve stems, in the suction side piping. This can result in dangerous bubbles in the transformer oil and may cause the gas detector or Buchholz relay to operate. Dissolved gas analysis will show a big increase in oxygen and nitrogen content [4]. High oxygen and nitrogen content can also be caused by gasket leaks elsewhere.

After 1 month of service and yearly, inspect water-oil heat exchangers. Test and inspect the pumps as mentioned above. Look for and repair leaks in piping and heat exchanger body. Examine the latest dissolved gas analysis results for dissolved moisture and free water. If free water is present and there are no gasket leaks, the water portion of the water-oil heat exchanger must be pressure tested. A leak may have developed, allowing water to migrate into the transformer oil, which can destroy the transformer. If the heat exchanges piping is double-walled, check the drain for water or oil; check manufacturer's instruction manual.

## 4. OIL-FILLED TRANSFORMER INSPECTIONS

A transformer maintenance program must be based on thorough routine inspections. These inspections must be in addition to normal daily/weekly data gathering trips to check oil levels and temperatures. Some monitoring may be done remotely using supervisory control and data acquisition (SCADA) systems, but this can never substitute for thorough inspections by competent maintenance or operations people.

### 4.1 Oil-Filled Transformers

After 1 month of service and once each year, make an in-depth inspection of oil-filled transformers. Before beginning, look carefully at temperature and oil level data sheets. If temperature, pressure, or oil level gages never change, even with seasonal temperature and loading changes, something is wrong.

The gauge may be stuck or data sheets may have been filled in incorrectly. Examine the DGA's for evidence of leaks, etc.

### 4.1.1 Transformer Tank.

Check for excessive corrosion and oil leaks. Pay special attention to flanges and gaskets (bushings, valves, and radiators) and lower section of the main tank. Report oil leaks to maintenance, and pay special attention to the oil level indicator if leaks are found. Severely corroded spots should be wire brushed and painted with a rust inhibitor.

### 4.1.2 Top Oil Thermometers.

These are typically sealed spiral-bourdon-tube dial indicators with liquid-filled bulb sensors. The bulb is normally inside a thermometer well, which penetrates the tank wall into oil near the top of the tank. As oil temperature increases in the bulb, liquid expands, which expands the spiral tube. The tube is attached to a pointer that indicates temperature. These pointers may also have electrical contacts to trigger alarms and start cooling fans as temperature increases. An extra pointer, normally red, indicates maximum temperature since the last time the indicator was reset. This red pointer rises with the main pointer but will not decrease unless manually reset; thus, it always indicates the highest temperature reached since being set. See the instruction manual on your specific transformer for details.

### 4.1.3 Winding Temperature Thermometers.

These devices are supposed to indicate hottest spot in the winding based on the manufacturers heat run tests. At best, this device is only accurate at top nameplate rated load and then only if it is not out of calibration [17]. They are not what their name implies and can be misleading. They are only winding hottest-spot simulators and not very accurate. There is no temperature sensor imbedded in the winding hot spot. At best, they provide only a rough approximation of hot spot winding temperature and should not be relied on for accuracy. They can be used to turn on additional cooling or activate alarms as the top oil thermometers do.

Winding temperature thermometers work the same as the top oil thermometer (4.1.2), except that the bulb is in a separate thermometer well near the top of the tank. A wire-type heater coil is either inserted into or wrapped around the thermometer well which surrounds the temperature sensitive bulb. In some transformers, a current transformer (CT) is around one of the three winding leads and provides current directly to the heater coil in proportion to winding current. In other transformers, the CT supplies current to an autotransformer that supplies current to the heater coil. The heater warms the bulb and the dial indicates a temperature, but it is not the true hottest-spot temperature.

These devices are calibrated at the factory by changing taps either on the CT or on the autotransformer, or by adjusting the calibration resistors in the control cabinet. They normally cannot be field calibrated or tested, other than testing the thermometer, as mentioned. The calibration resistors can be adjusted in the field if the manufacturer provides calibration curves for the transformer. In practice, most winding temperature indicators are out of calibration, and their readings are meaningless. These temperature indications should not be relied upon for loading operations or maintenance decisions.

Fiber optic temperature sensors can be imbedded directly into the winding as the transformer is being built and are much more accurate. This system is available as an option on new transformers at an increased cost, which may be worth it since the true winding "hottest-spot" temperature is critical when higher loading is required.

Thermometers can be removed without lowering the transformer oil if they are in a thermometer well. Check your transformer instruction manual. Look carefully at the capillary tubing between the thermometer well and dial indicator. If the tubing has been pinched or accidentally struck, it may be restricted. This is not an obvious defect, and it can cause the dial pointer to lock in one position. If this defect is found, the whole gauge must be returned to the factory for repair or replacement; it cannot be repaired in the field. Look for a leak in the tubing system; the gauge will be reading very low and must be replaced if a leak is discovered. Thermometers should be removed and tested every 3 to 5 years as described here.

### Thermometer Testing.

Every 3 to 5 years, and if trouble is suspected, do a thermometer testing. Suspend the indicator bulb and an accurate mercury thermometer in an oil bath. Do not allow either to touch the side or bottom of the container. Heat the oil on a hotplate while stirring and compare the two thermometers while the temperature increases. If a magnetic stirring/heating plate is available, it is more effective than hand stirring. Pay particular attention to the upper temperature range at which your transformers normally operate (50°C to 80°C). An ohmmeter should also be used to check switch operations. If either dial indicator is more than 5°C different than the mercury thermometer, it should be replaced with a spare. A number of spares should be kept, based on the quantity of transformers at the plant.

The alarms and other functions should also be tested to see if the correct annunciator points activate, pumps/fans operate, etc.

If it is not possible to replace the temperature gauge or send it to the factory for repair, place a temperature correction factor on your data form to add to the dial reading so the correct temperature will be recorded. Also lower the alarm and pump-turn-on settings by this same correction factor. Since these are pressure-filled systems, the indicator will typically read low if it is out of calibration. Field testing has shown some of these gauges reading 15°C to 20°C lower than actual temperature. This is hazardous for transformers because it will allow them to continuously run hotter than intended, due to delayed alarms and cooling activation. If thermometers are not tested and errors corrected, transformer service life may be shortened or premature failure may occur.

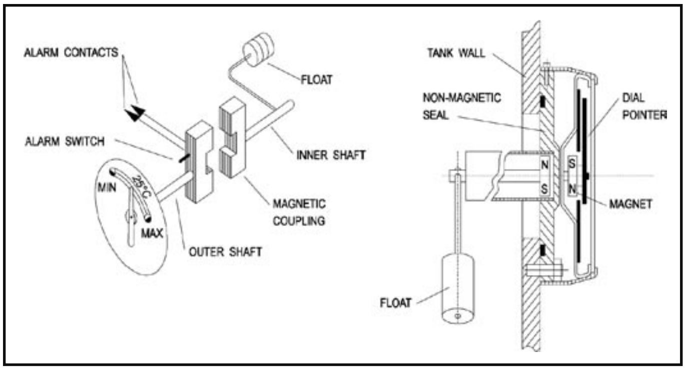


**Figure 2. — Oil Level Indicator.**

### 4.1.4 Oil Level Indicators.

After one month of service, inspect and every 3 to 5 years, check the tank oil level indicators. These are float operated, with the float mechanism magnetically coupled through the tank wall to the dial indicator. As level increases, the float rotates a magnet inside the tank. Outside the tank, another magnet follows (rotates), which moves the pointer. The center of the dial is normally marked with a temperature 25°C (77°F). High and low level points are also marked to follow level changes as the oil expands and contracts with temperature changes. The proper way to determine accurate oil level is to first look at the top oil temperature indicator. After determining the temperature, look at the level gauge. The pointer should be at a reasonable level corresponding to the top oil temperature. If the transformer is fully loaded, the top oil temperature will be high, and the level indicator should be near the high mark. If the transformer is de-energized and the top oil temperature is near 25°C, the oil level pointer should be at or near 25°C.

To check the level indicator, you can remove the outside mechanism for testing without lowering transformer oil. After removing the gauge, hold a magnet on the back of the dial and rotate the magnet; the dial indicator should also rotate. If it fails to respond or if it drags or sticks, replace it. As mentioned above, defective units can be sent to the factory for repair.

There may also be electrical switches for alarms and possibly tripping off the transformer on falling tank level. These should be checked with an ohmmeter for proper operation. The alarm/tripping circuits should also be tested to see if the correct annunciator points and relays respond. See the transformer instruction book for information on your specific indicator.

If oil has had to be lowered in the transformer or conservator for other reasons (e.g. inspections), check the oil level float mechanism. Rotate the float mechanism by hand to check for free movement. Check the float visually to make sure it is secure to the arm and that the arm is in the proper shape. Some arms are formed (not straight).

### 4.1.5 Pressure Relief Devices.

These devices are the transformer's last line of defense against excessive internal pressure. In case of a fault or short circuit, the resultant arc instantly vaporizes surrounding oil, causing a rapid buildup of gaseous pressure. If the pressure relief device does not operate properly and pressure is not sufficiently relieved within a few milliseconds, a catastrophic tank rupture can result, spreading flaming oil over a wide area. Two types of these devices are discussed here. The instruction manual for your transformer must be consulted for specifics.

Caution: Never paint pressure-relief devices because paint can cause the plunger or rotating shaft to stick. Then the device might not relieve pressure, which could lead to catastrophic tank failure during a fault. Look at the top of the device; on newer units, a yellow or blue button should be visible. If these have been painted, the button will be the same color as the tank. On older units, a red flag should be visible; if it has been painted, it will be the same color as the tank.

If they have been painted, they should be replaced. It is virtually impossible to remove all paint from the mechanism and be certain the device will work when needed.

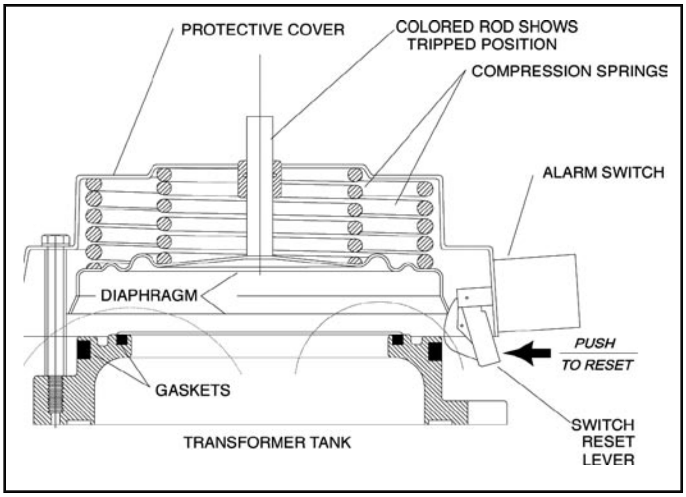


**Figure 3. — Pressure Relief Device.**

#### Newer Pressure Relief Devices.

New pressure relief devices are spring-loaded valves that automatically reclose following a pressure release. The springs are held in compression by the cover and press on a disc which seals an opening in the tank top. If pressure in the tank exceeds operating pressure, the disk moves upward and relieves pressure. As pressure decreases, the springs reclose the valve. After operating, this device leaves a brightly colored rod (bright yellow for oil, blue for silicone), exposed approximately 2 inches above the top. This rod is easily seen upon inspection, although it is not always visible from floor level. The rod may be reset by pressing on the top until it is again recessed into the device. The switch must also be manually reset. A relief device is shown in the open position in figure 3.

Caution: Bolts that hold the device to the tank may be loosened safely, but never loosen screws that hold the cover to the flange without referring to the instruction manual and using great care. Springs that oppose tank pressure are held in compression by these screws, and their stored energy could be hazardous.

Once each year, and as soon as possible after a known through-fault or internal fault, inspect pressure devices to see if they have operated. This must be done from a high-lift bucket if the transformer is energized. Look at each pressure relief device to see if the yellow (or blue) button is visible. If the device has operated, about 2 inches of the colored rod will be visible. Each year, test the alarm circuits by operating the switch by hand and making sure the correct annunciator point is activated. If the relief device operates during operation, do not re-energize the transformer; Doble and other testing may be required before re-energizing, and an oil sample should be sent for analysis

Every 3 to 5 years, when doing other maintenance or testing, if the transformer has a conservator, examine the top of the transformer tank around the pressure relief device. If oil is visible, the device is leaking, either around the tank gasket or relief diaphragm. If the device is 30 years old, replace the whole unit. A nitrogen blanketed transformer will use a lot more nitrogen if the relief device is leaking; they should be tested as described here.

A test stand with a pressure gauge may be fabricated to test the pressure relief function. The cost of a pressure relief device is not inconsequential, so testing instead of replacement may be prudent. Have a spare on hand so that the tank will not have to be left open. If the tank top or pressure relief device has gasket-limiting grooves, always use a nitrile replacement gasket; if there are no grooves, use a cork-nitrile gasket. Relief devices themselves do not leak often; the gasket usually leaks.

**Older Pressure Relief Devices.**

Older pressure relief devices have a diaphragm and a relief pin that is destroyed each time the device operates and must be replaced.

Caution: These parts must be replaced with exact replacement parts, or the operating relief-pressure of the device will be wrong.

The relief pin determines operating pressure; a number, which is the operating pressure, normally appears on top of the pin. Check your specific transformer instruction manual for proper catalog numbers. Do not assume you have the right parts, or that correct parts have been previously installed — look it up. If the operating pressure is too high, a catastrophic tank failure could result.

On older units, a shaft rotates, operates alarm/trip switches, and raises a small red flag when the unit releases pressure. If units have been painted or are more than 30 years old, they should be replaced with the new model as soon as it is possible to have a transformer outage.

Once each year and as soon as possible after a through-fault or internal fault, examine the indicator flag to see if the device has operated. They must be examined from a high-lift bucket if the transformer is energized. A clearance must be obtained to test, repair, or reset the device. See the instruction manual for the specific transformer. Test alarm/trip circuits by operating the switch by hand. Check to make sure the correct annunciator point activates.

Every 3 to 5 years, when doing other maintenance or testing, examine the top of the transformer tank around the pressure relief device. If the transformer has a conservator and oil is visible, the device is leaking, either around the tank gasket or relief diaphragm. The gasket and/or device must be replaced. Take care that the new device will fit the same tank opening prior to ordering.

### 4.1.6 Sudden Pressure Relay.

Internal arcing in an oil-filled power transformer can instantly vaporize surrounding oil, generating gas pressures that can cause catastrophic failure, rupture the tank, and spread flaming oil over a large area. This can damage or destroy other equipment in addition to the transformer and presents extreme hazards to workers.

The relay is designed to detect a sudden pressure increase caused by arcing. It is set to operate before the pressure relief device. The control circuit should de-energize the transformer and provide an alarm. The relay will ignore normal pressure changes such as oil-pump surges, temperature changes, etc.

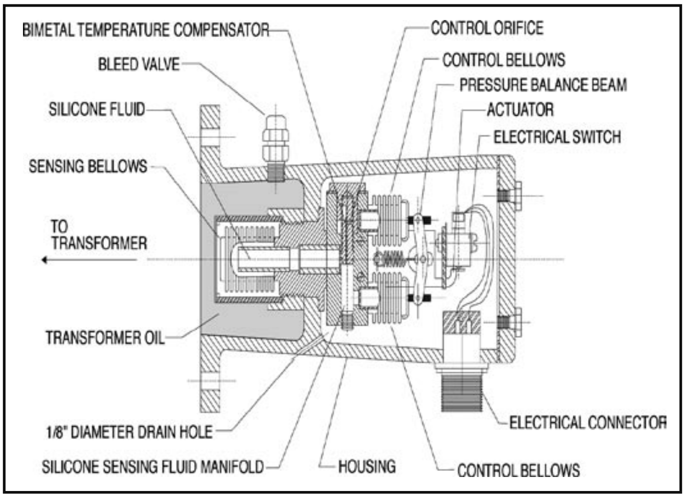


**Figure 4. — Sudden Pressure Relay.**

Modern sudden pressure relays consist of three bellows (see figure 4) with silicone sealed inside. Changes in pressure in the transformer deflect the main sensing bellows. Silicone inside acts on two control bellows arranged like a balance beam, one on each side. One bellows senses pressure changes through a small orifice. The opening is automatically changed by a bimetallic strip to adjust for normal temperature changes of the oil. The orifice delays pressure changes in this bellows. The other bellows responds to immediate pressure changes and is affected much more quickly. Pressure difference tilts the balance beam and activates the switch.

This type relay automatically resets when the two bellows again reach pressure equilibrium. If this relay operates, do not re-energize the transformer until you have determined the exact cause and corrected the problem.

Old style sudden pressure relays have only one bellows. A sudden excessive pressure within the transformer tank exerts pressure directly on the bellows, which moves a spring-loaded operating pin. The pin operates a switch which provides alarm and breaker trip. After the relay has operated, the cap must be removed and the switch reset to normal by depressing the reset button.

Once every 3 to 5 years, the sudden pressure relay should be tested according to manufacturer's instructions. Generally, only a squeeze-bulb and pressure gage (5 psi) are required. Disconnect the tripping circuit and use an ohmmeter to test for relay operation. Test the alarm circuit and verify that the correct alarm point is activated. Use an ohmmeter to verify the trip signal is activated or, if possible, apply only control voltage to the breaker and make sure the tripping function operates. Consult the manufacturer's manual for your specific transformer for detailed instructions.

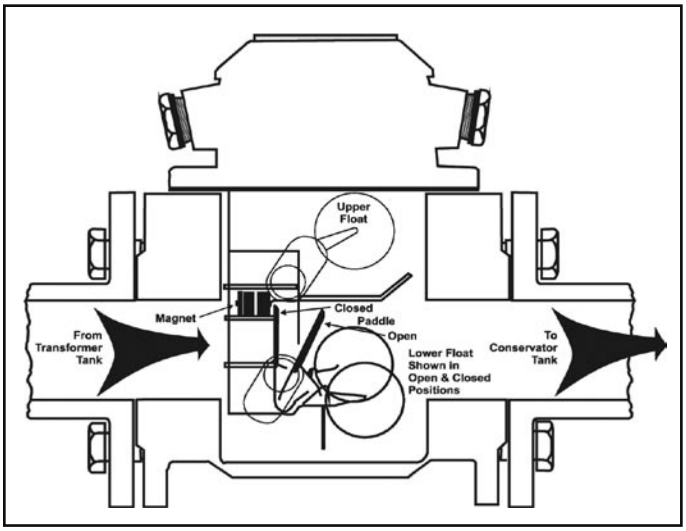


Figure 5. — Bucholz Relay.

### 4.1.7 Buchholz Relay (found only on transformers with conservators).

The Buchholz relay has two oil-filled chambers with floats and relays arranged vertically one over the other. If high eddy currents, local overheating, or partial discharges occur within the tank, bubbles of resultant gas rise to the top of the tank. These rise through the pipe between the tank and the conservator. As gas bubbles migrate along the pipe, they enter the Buchholz relay and rise into the top chamber. As gas builds up inside the chamber, it displaces the oil, decreasing the level. The top float descends with oil level until it passes a magnetic switch which activates an alarm. The bottom float and relay cannot be activated by additional gas buildup. The float is located slightly below the top of the pipe so that once the top chamber is filled, additional gas goes into the pipe and on up to the conservator. Typically, inspection windows are provided so that the amount of gas and relay operation may be viewed during testing. If the oil level falls low enough (conservator empty), switch contacts in the bottom chamber are activated by the bottom float. These contacts are typically connected to cause the transformer to trip. This relay also serves a third function, similar to the sudden pressure relay. A magnetically held paddle attached to the bottom float is positioned in the oil-flow stream between the conservator and transformer tank. Normal flows resulting from temperature changes are small and bypass below the paddle. If a fault occurs in the transformer, a pressure wave (surge) is created in the oil. This surge travels through the pipe and displaces the paddle. The paddle activates the same magnetic switch as the bottom float mentioned above, tripping the transformer. The flow rate at which the paddle activates the relay is normally adjustable. See your specific transformer instruction manual for details.

Once every 3 to 5 years while the transformer is de-energized, functionally test the Buchhholz relay by pumping a small amount of air into the top chamber with a squeeze bulb hand pump. Watch the float operation through the window. Check to make sure the correct alarm point has been activated. Open the bleed valve and vent air from the chamber. The bottom float and switching cannot be tested with air pressure. On some relays, a rod is provided so that you can test both bottom and top sections by pushing the floats down until the trip points are activated. If possible, verify that the breaker will trip with this operation. A volt-ohmmeter may also be used to check the switches. If these contacts activate during operation, it means that the oil level is very low, or a pressure wave has activated (bottom contacts), or the transformer is gassing (top contacts). If this relay operates, do not re-energize the transformer until you have determined the exact cause.

### 4.1.8 Transformer Bushings: Testing and Maintenance of High-Voltage Bushings.

When bushings are new, they should be Doble tested as an acceptance test. Refer to the M4000 Doble test set instructions, the Doble Bushing Field Test Guide [8], and the manufacturer's data for guidance on acceptable results.

Caution: Do not test a bushing while it's in its wooden shipping crate, or while it is lying on wood. Wood is not as good an insulator as porcelain and will cause the readings to be inaccurate. Keep the test results as a baseline record to compare with future tests.

After 1 month of service and yearly, check the external porcelain for cracks and/or contamination (requires binoculars). There is no "perfect insulator"; a small amount of leakage current always exists. This current "leaks" through and along the bushing surface from the high-voltage conductor to ground. If the bushing is damaged or heavily contaminated, leakage current becomes excessive, and visible evidence may appear as carbon tracking (treeing) on the bushing surface. Flashovers may occur if the bushings are not cleaned periodically.

Look carefully for oil leaks. Check the bushing oil level by viewing the oil-sight glass or the oil level gage. When the bushing has a gage with a pointer, look carefully, because the oil level should vary a little with temperature changes. If the pointer never changes, even with wide ambient temperature and load changes, the gage should be checked at the next outage. A stuck gage pointer coupled with a small oil leak can cause explosive failure of a bushing, damaging the transformer and other switchyard equipment. A costly extended outage is the result.

If the oil level is low and there is an external oil leak, check the bolts for proper torque and the gasket for proper compression. If torque and compression are correct, the bushing must be replaced with a spare. Follow instructions in the transformer manual carefully. It is very important that the correct type gasket be installed and the correct compression be applied. A leaky gasket is probably also leaking water and air into the transformer, so check the most recent transformer DGA for high moisture and oxygen.

If the oil level is low and there is no visible external leak, there may be an internal leak around the lower seal into the transformer tank. If possible, re-fill the bushing with the same oil and carefully monitor the level and the volume it takes to fill the bushing to the proper level. If it takes more than one quart, make plans to replace the bushing. The bushing must be sent to the factory for repair or it must be junked; it cannot be repaired in the field.

Caution: Never open the fill plug of any bushing if it is at an elevated temperature. Some bushings have a nitrogen blanket on top of the oil, which pressurizes as the oil expands. Always consult the manufacturer's instruction manual which will give the temperature range at which the bushing may be safely opened. Generally, this will be between 15 °C (59 °F) and 35 °C (95 °F). Pressurized hot oil may suddenly gush from the fill plug if it is removed while at elevated temperature, causing burn hazards. Generally, the bushing will be a little cooler than the top oil temperature, so this temperature gage may be used as a guide if the gage has been tested as mentioned in 4.1.3.

About 90% of all preventable bushing failures are caused by moisture entering through leaky gaskets, cracks, or seals. Internal moisture can be detected by Doble testing. See FIST 3-2 [9] and Doble Bushing Field Test Guide [8] for troubles and corrective actions. Internal moisture causes deterioration of the insulation of the bushing and can result in explosive failure, causing extensive transformer and other equipment damage, as well as hazards to workers.

After 1 month of service and yearly, examine the bushings with an IR camera [4,7]; if one phase shows a markedly higher temperature, there is probably a bad connection. The connection at the top is usually the poor one; however, a bad connection inside the transformer tank will usually show a higher temperature at the top as well. In addition, a bad connection inside the transformer will usually show hot metal gases (ethane and ethylene) in the DGA.

Once every 3 to 5 years, a close physical inspection and cleaning should be done [9]. Check carefully for leaks, cracks, and carbon tracking. This inspection will be required more often in atmospheres where salts and dust deposits appear on the bushings. In conditions that produce deposits, a light application of Dow Corning grease DC-5 or GE Insulgel will help reduce risk of external flashover. The downside of this treatment is that a grease buildup may occur. In high humidity and wet areas, a better choice may be a high quality silicone paste wax applied to the porcelain, which will reduce the risk of flashover. A spray-on wax containing silicone, such as Turtle Wax brand, has been found to be very useful for cleaning and waxing in one operation, providing the deposits are not too hard. Wax will cause water to form beads rather than a continuous sheet, which reduces flashover risk. Cleaning may involve just spraying with Turtle Wax and wiping with a soft cloth. A lime removal product, such as "Lime Away," also may be useful. More stubborn contaminates may require solvents, steel wool, and brushes. A high pressure water stream may be required to remove salt and other water soluble deposits. Limestone powder blasting with dry air will safely remove metallic oxides, chemicals, salt-cake, and almost any hard contaminate. Other materials, such as potters clay, walnut or pecan shells, or crushed coconut shells, are also used for hard contaminates. Carbon dioxide (CO2) pellet blasting is more expensive but virtually eliminates cleanup because it evaporates. Ground up corn-cob blasting will remove soft pollutants such as old coatings of built-up grease. A competent experienced contractor should be employed and a thorough written job hazard analysis (JHA) performed when any of these treatments are used.

Corona (air ionization) may be visible at tops of bushings at twilight or night, especially during periods of rain, mist, fog, or high humidity. At the top, corona is considered normal; however, as a bushing becomes more and more contaminated, corona will creep lower and lower. If the bushing is not cleaned, flashover will occur when corona nears the grounded transformer top. If corona seems to be lower than the top of the bushing, inspect, Doble test, and clean the bushing as quickly as possible. If flashover occurs (phase to ground fault), it could destroy the bushing and cause an extended outage. Line-to-line faults also can occur if all the bushings are contaminated and flashover occurs. A corona scope may be used to view and photograph low levels of corona indoors under normal illumination and outdoors at twilight or night. High levels of corona may possibly be viewed outdoors in the daytime if a dark background is available, such as trees, canyon walls, buildings, etc. The corona scope design is primarily for indoor and night time use; it cannot be used with blue or cloudy sky background. This technology is available at the Technical Service Center (TSC), D-8450.

Caution: See the transformer manual for detailed instructions on cleaning and repairing your specific bushing surfaces. Different solvents, wiping materials, and cleaning methods may be required for different bushings. Different repair techniques may also be required for small cracks and chips. Generally, glyptal or insulating varnish will repair small scratches, hairline cracks, and chips. Sharp edges of a chip should be honed smooth, and the defective area painted with insulating varnish to provide a glossy finish. Hairline cracks in the surface of the porcelain must be sealed because accumulated dirt and moisture in the crack may result in flashover. Epoxy should be used to repair larger chips. If a bushing insulator has a large chip that reduces the flashover distance or has a large crack totally through the insulator, the bushing must be replaced. Some manufacturers offer repair service to damaged bushings that cannot be repaired in the field.

Contact the manufacturer for your particular bushings if you have repair questions.

Once every 3 to 5 years, depending on the atmosphere and service conditions, the bushings should be Doble tested. Refer to Doble M-4000 test set instructions, Doble Bushing Field Test Guide [8], FIST 3-2, [9] and the manufacturer's instructions for proper values and test procedures. Bushings should be cleaned prior to Doble testing. Contamination on the insulating surface will cause the results to be inaccurate. Testing may also be done before and after cleaning to check methods of cleaning. As the bushings age and begin to deteriorate, reduce the testing interval to 1 year. Keep accurate records of results so that replacements can be ordered in advance, before you have to remove bushings from service.

## 4.2 Oil Preservation Sealing Systems

The purpose of sealing systems is to prevent air and moisture from contaminating oil and cellulose insulation. Sealing systems are designed to prevent oil inside the transformer from coming into contact with air. Air contains moisture, which causes sludging and an abundant supply of oxygen. Oxygen in combination with moisture causes greatly accelerated deterioration of the cellulose. This oxygen-moisture combination will greatly reduce service life of the transformer.

Sealing systems on many existing Reclamation power transformers are of the inert gas (nitrogen) pressure design; however, we have many other designs. Current practice is to buy only conservator designs with bladders for transformer voltages 115 kV and above and capacities above 10 mega-volt-amps (mva). Below these values, we buy only inert gas pressure system transformers, as depicted in figure 8.

Some of the sealing systems are explained below. There may be variations of each design, and not every design is covered. The order below is roughly from earlier to more modern.

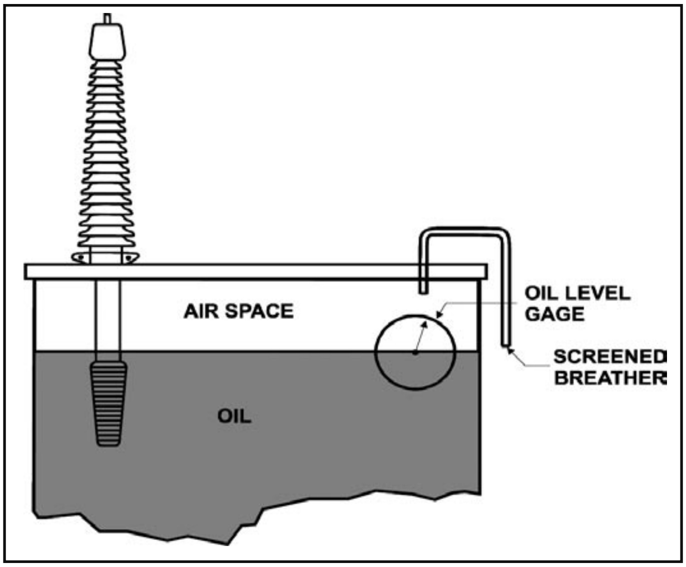


Figure 6. — Free breathing transformer.

### 4.2.1 Sealing Systems Types.

**Free Breathing**

Sealing systems have progressed from early designs of "free breathing" tanks, in which an air space on top of the oil is vented to atmosphere through a breather pipe. The pipe typically is screened to keep out insects and rodents and turned down to prevent rain from entering. Breathing is caused by expansion and contraction of the oil as temperature changes. These earlier designs did not use an air dryer, and condensation from moisture formed on inside walls and tank top. Moisture, oxygen, and nitrogen would also dissolve directly into oil from the air. This was not the best design. As mentioned before, a combination of oxygen and moisture accelerates deterioration of cellulose insulation. Moisture also decreases dielectric strength, destroying insulating quality of the oil, and causes formation of sludge. If you have one or more of these earlier design transformers, it is recommended that a desiccant type air dryer be added to the breather pipe.

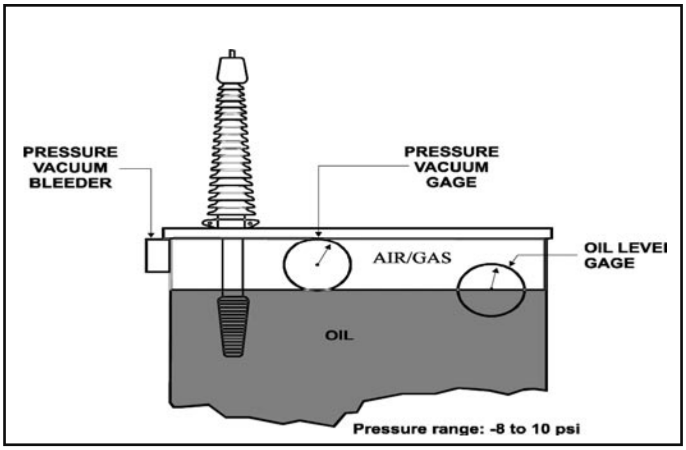


Figure 7. — Pressurized Breathing Transformer.

### Sealed or Pressurized Breathing.

This design is similar to the free breathing one with addition of a pressure/vacuum bleeder valve. When the transformer was installed, pressurized dry air or nitrogen was placed on top of the oil. The bleeder valve is designed to hold pressure inside to approximately plus or minus 5 psi (figure7). The same problems with moisture and oxygen occur as previously described. Problems are not as severe because "breathing" is limited by the bleeder valve. Air or N2 is exhausted to the outside atmosphere when a positive pressure more than 5 psi occurs inside the tank. This process does not add moisture and oxygen to the tank. However, when cooling, the oil contracts and, if pressure falls 5 psi below the outside atmosphere, the valve allows outside air into the tank, which pulls in moisture and oxygen.

Once each year, check the pressure gage against the weekly data sheets; if the pressure never varies with seasonal temperature changes, the gage is defective. Add nitrogen if the pressure falls below 1 psi to keep moisture laden air from being pulled in. Add enough N2 to bring the pressure to 2 to 3 psi.

### Pressurized Inert Gas Sealed System.

This system keeps space above the oil pressurized with a dry inert gas, normally nitrogen (figure 8). This design prevents air and moisture from coming into contact with insulating oil. Pressure is maintained by a nitrogen gas bottle with the pressure regulated normally between 0.5 and 5 psi. Pressure gages are provided in the nitrogen cubicle for both high and low pressures (figure 9). A pressure/vacuum gage is normally connected to read low pressure gas inside the tank. This gage may be located on the transformer and normally has high-and low-pressure alarm contacts. See section 4.2.2 which follows.

Caution: When replacing nitrogen cylinders, do not just order a "nitrogen cylinder" from the local welding supplier. Nitrogen for transformers should meet ASTM D-1933 Type III with -59°C dew point as specified in IEEE C-57.12.00-1993, paragraph 6.6.3 [27, 2].

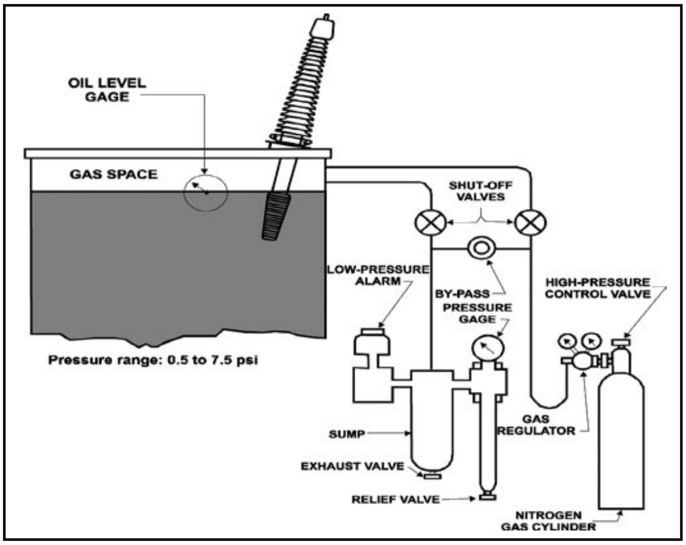


Figure 8. — Pressurized Inert Gas Transformer.

### 4.2.2 Gas Pressure Control Components.

After 1 month of service and yearly, inspect the gas pressure control components. There is normally an adjustable, three-element pressure control system for inert gas, which maintains a pressure range of 0.5 to 5 psi in the transformer tank. There is also a bleeder valve that exhausts gas to atmosphere when pressure exceeds relief pressure of the valve, normally 5 to 8 psi.

Caution: The component part descriptions below are for the typical three-stage pressure regulating equipment supplying inert gas to the transformer. Your particular unit may be different, so check your transformer instruction manual.

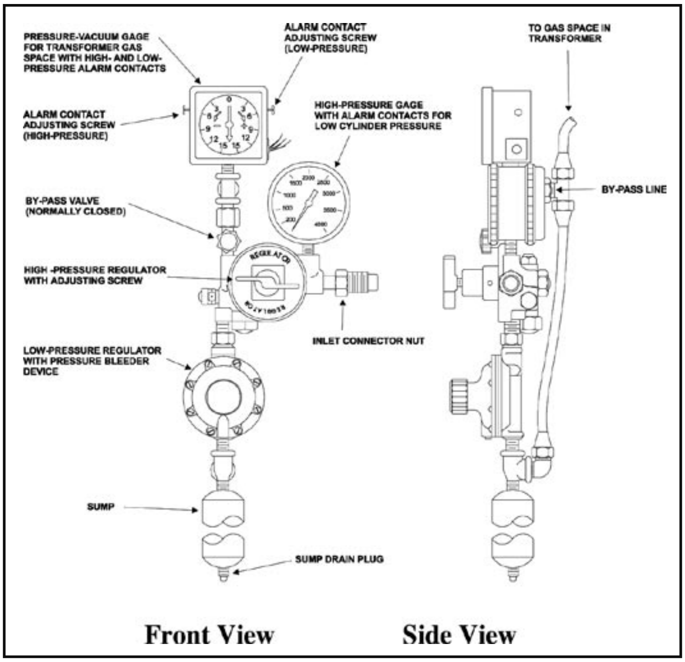

PRESSURE-VACUUM GAGE FOR TRANSFORMER GAS SPACE WITH HIGH- AND LOW-PRESSURE ALARM CONTACTS
ALARM CONTACT ADJUSTING SCREW (LOW-PRESSURE)
TO GAS SPACE IN TRANSFORMER
ALARM CONTACT ADJUSTING SCREW (HIGH-PRESSURE)
HIGH-PRESSURE GAGE WITH ALARM CONTACTS FOR LOW CYLINDER PRESSURE
BY-PASS LINE
BY-PASS VALVE (NORMALLY CLOSED)
HIGH -PRESSURE REGULATOR WITH ADJUSTING SCREW
REGULATOR
INLET CONNECTOR NUT
LOW-PRESSURE REGULATOR WITH PRESSURE BLEEDER DEVICE
SUMP
SUMP DRAIN PLUG
Front View
Side View

Figure 9. — Gas Pressure Control Components.

### High-Pressure Gage.

The high-pressure gauge is attached between the nitrogen cylinder and high-pressure regulator that indicates cylinder pressure. When the cylinder is full, the gauge will read approximately 2,400 psi. Normally, the gauge will be equipped with a low-pressure alarm that activates when the cylinder is getting low (around 500 psi). However, gas will still be supplied, and the regulating equipment will continue to function until the cylinder is empty. Refer to figure 9 for the following descriptions.

### High-Pressure Regulator.

The high-pressure regulator has two stages. The input of the first stage is connected to the cylinder, and the output of the first stage is connected internally to the input of the second stage. This holds output pressure of the second stage constant. The first stage output is adjustable by a hand-operated lever and can deliver a maximum of whatever pressure is in the cylinder (2,400 psi when full) down to zero. The second stage output is varied by turning the adjusting screw, normally adjusted to supply approximately 10 psi to the input of the low pressure regulator.

### Low-Pressure Regulator.

The low-pressure regulator is the third stage and controls pressure and flow to the gas space of the transformer. The input of this regulator is connected to the output of the second stage (approximately 10 psi). This regulator is typically set at the factory to supply gas to the transformer at a pressure of approximately 0.5 psi and needs no adjustment. If a different pressure is required, the regulator can be adjusted by varying spring tension on the valve diaphragm. Pressure is set at this low value because major pressure changes inside the transformer come from expansion and contraction of oil. The purpose of this gas feed is to make up for small leaks in the tank gaskets and elsewhere so that air cannot enter. Typically, a spring-loaded bleeder for high-pressure relief is built into the regulator and is set at the factory to relieve pressures in excess of 8 psi. The valve will close when pressure drops below the setting, preventing further loss of gas.

### Bypass Valve Assembly.

The bypass valve assembly opens a bypass line around the low pressure regulator and allows the second stage of the high-pressure regulator to furnish gas directly to the transformer. The purpose of this assembly is to allow much faster filling/purging of the gas space during initial installation or if the transformer tank has to be refilled after being opened for inspection.
Caution: During normal operation, the bypass valve must be closed, or pressure in the tank will be too high.

### Oil Sump.

The oil sump is located at the bottom of the pressure regulating system between the low-pressure regulator and shutoff valve C. The sump collects oil and/or moisture that may have condensed in the low pressure fill line. The drain plug at the bottom of the sump should be removed before the system is put into operation and also removed once each year during operation to drain any residual oil in the line. This sump and line will be at the same pressure as the gas space in the top of the transformer. The sump should always be at a safe pressure (less than 10 psi) so the plug can be removed to allow the line to purge a few seconds and blow out the oil. However, always look at the gas space pressure gage on the transformer or the low pressure gage in the nitrogen cabinet, just to be sure, before removing the drain plug.

### Shutoff Valves.

The shutoff valves are located near the top of the cabinet for the purpose of isolating the transformer tank for shipping or maintenance. These valves are normally of double-seat construction and should be fully opened against the stop to prevent gas leakage around the stem. A shutoff valve is also provided for the purpose of shutting off the nitrogen flow to the transformer tank. This shutoff valve must be closed prior to changing cylinders to keep the gas in the transformer tank from bleeding off.

### Sampling and Purge Valve.

The sampling and purge valve is normally located in the upper right of the nitrogen cabinet. This valve is typically equipped with a hose fitting; the other side is connected directly to the transformer gas space by copper tubing. This valve is opened while purging the gas space during a new installation or maintenance refill and provides a path to exhaust air as the gas space is filled with nitrogen. This valve is also opened when a gas sample is taken from the gas space for analysis. When taking gas samples, the line must be sufficiently purged so that the sample will be from gas above the transformer oil and not just gas in the line. This valve must be tightly closed during normal operation to prevent gas leakage.

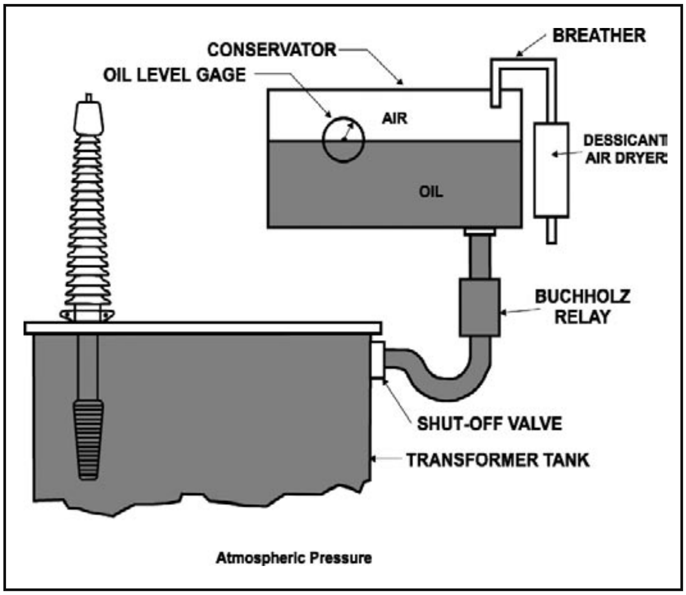


Figure 10. — Free Breathing Conservator.

### Free Breathing Conservator.

This design adds an expansion tank (conservator) above the transformer so that the main tank may be completely filled with oil. Oil expansion and air exchange with the atmosphere (breathing) occurs away from the oil in the transformer. This design reduces oxygen and moisture contamination because only a small portion of oil is exchanged between the main tank and conservator. An oil/air interface still exists in the conservator, exposing the oil to air. Eventually, oil in the conservator is exchanged with oil in the main tank, and oxygen and other contaminates gain access to the insulation.

If you have transformers of this design, it is recommended that a bladder or diaphragm-type conservator be installed (described below) or retrofitted to the original conservator. In addition, a desiccant-type air dryer should also be installed.

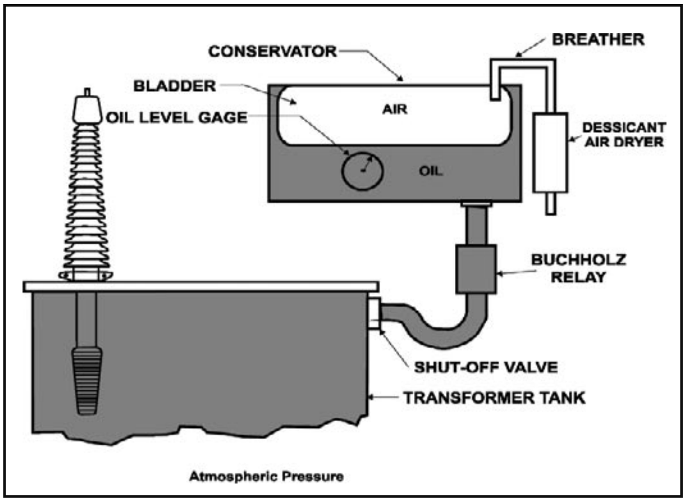


Figure 11. — Conservator with Bladder.

## Conservator with Bladder or Diaphragm Design.

A conservator with bladder or diaphragm is similar to the design above with an added air bladder (balloon) or flat diaphragm in the conservator. The bladder or diaphragm expands and contracts with the oil and isolates it from the atmosphere. The inside of the bladder or top of the diaphragm is open to atmospheric pressure through a desiccant air dryer. As oil expands and contracts and as atmospheric pressure changes, the bladder or diaphragm "breathes" air in and out. This keeps air and transformer oil essentially at atmospheric pressure. The oil level gage on the conservator typically is magnetic, like those mentioned earlier, except the float is positioned near the center of the underside of the bladder. With a diaphragm, the level indicator arm rides on top of the diaphragm. Examine the air dryer periodically and change the desiccant when approximately one-third of the material changes color.

Note: A vacuum will appear in the transformer if piping between the air dryer and conservator is too small, if the air intake to the dryer is too small, or if the piping is partially blocked. The bladder cannot take in air fast enough when the oil level is decreasing due to rapidly falling temperature. Minimum 3/4- to 1-inch piping is recommended. This problem is especially prevalent with transformers that are frequently in and out of service and located in geographic areas of large temperature variations. This situation may allow bubbles to form in the oil and may even activate gas detector relays such as the Buchholz and/or bladder failure relay. The vacuum may also pull in air around gaskets that are not tight enough or that have deteriorated (which may also cause bubbles) [4].

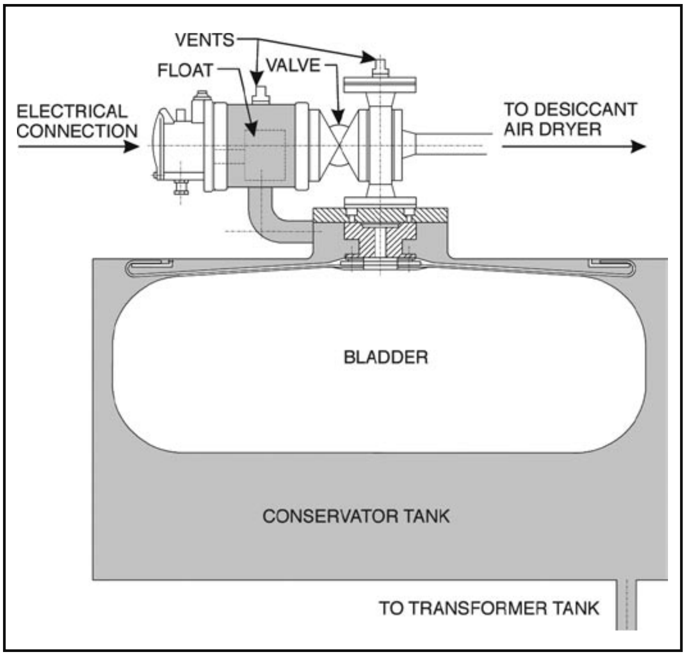


Figure 12. — Bladder Failure Relay.

## Bladder Failure (Gas Accumulator) Relay.

The bladder failure relay (not on diaphragm-type conservators) is mounted on top the conservator for the purpose of detecting air bubbles in the oil. Shown above (figure 12) is a modern relay. Check your transformer instruction manual for specifics because designs vary with manufacturers. No bladder is totally impermeable, and a little air will migrate into the oil. In addition, if a hole forms in the bladder, allowing air to migrate into the oil, the relay will detect it. As air rises and enters the relay, oil is displaced and the float drops, activating the alarm. It is similar to the top chamber of a Buchholz relay, since it is filled with oil and contains a float switch.

Caution: Never open the vent of the bladder failure relay unless you have vacuum or pressure equipment available. The oil will fall inside the relay and conservator and pull in air from the outside. You will have to re-commission the relay by valving off the conservator and pressurizing the bladder or by placing a vacuum on the relay. See your specific transformer instruction manual for details.

Caution: When the transformer, relay, and bladder are new, some air or gas is normally entrapped in the transformer and piping and takes a while to rise and activate the relay. Do not assume the bladder has failed if the alarm activates within 2 to 3 months after it is put into operation. If this occurs, you will have to re-commission the relay with pressure or vacuum. See your specific transformer instruction manual for details. If no more alarms occur, the bladder is intact. If alarms continue, look carefully for oil leaks in the conservator and transformer. An oil leak is usually also an air leak. This may be checked by looking at the nitrogen and oxygen in the dissolved gas analysis. If these gases are increasing, there is probably a leak; with a sealed conservator, there should be little of these gasses in the oil. Nitrogen may be high if the transformer was shipped new filled with nitrogen.

Every 3 to 5 years, (if the conservator has a diaphragm) remove the conservator inspection flange and look inside with a flashlight. If there is a leak, oil will be on top of the diaphragm, and it must be replaced. The new diaphragm material should be nitrile. If the conservator has a bladder and a bladder failure relay, the relay will alarm if the bladder develops a leak. If the conservator has a bladder and does not have a bladder failure relay, inspect the bladder by removing the mounting flange and look inside with a flashlight. If there is oil in the bottom of the bladder, a failure has definitely occurred, and the bladder must be replaced. Follow procedures in the specific transformer instruction manual for draining the conservator and replacement; designs and procedures vary and will not be covered here.

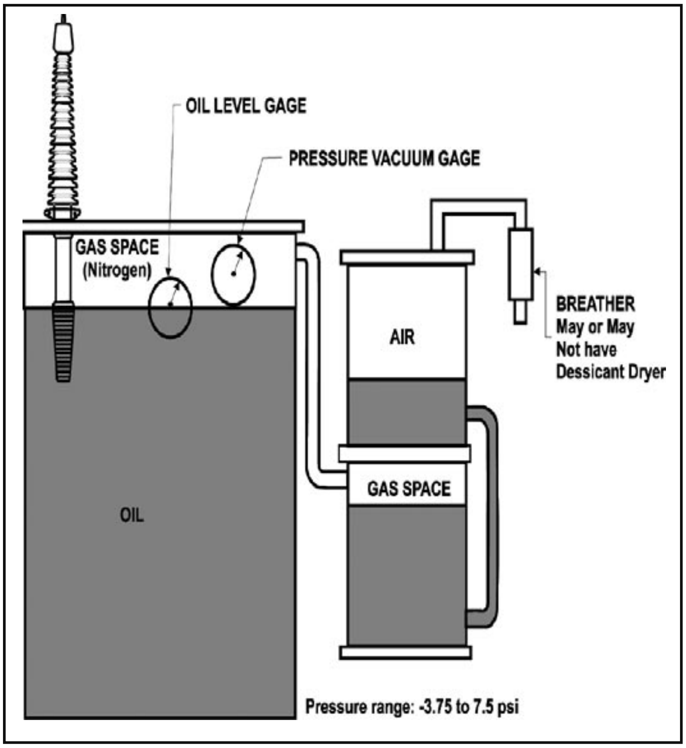

OIL LEVEL GAGE
PRESSURE VACUUM GAGE
GAS SPACE (Nitrogen)
AIR
BREATHER May or May Not have Dessicant Dryer
GAS SPACE
OIL
Pressure range: -3.75 to 7.5 psi

Figure 13. — Auxiliary Sealing System

### Auxiliary Tank Sealing System.

The auxiliary tank sealing system incorporates an extra tank between the main transformer tank and the conservator tank. Inert gas (normally nitrogen) is placed above oil in both the main and middle tanks. Only oil in the top conservator tank is exposed to air. A desiccant air dryer may or may not be included on the breather. As oil in the main tank expands and contracts with temperature, gas pressure varies above the oil in both (figure 13).

Changes in gas pressure causes oil to go back and forth between the middle tank and the conservator. Air containing oxygen and moisture is not in contact with oil in the main transformer tank. Oxygen and moisture are absorbed by oil in the conservator tank and interchanged with oil in the middle one. However, since gas in the middle tank interchanges with gas in the main tank, small amounts of oxygen and moisture carried by gas still make their way into the transformer.

With this arrangement, the conservator does not have to be located above the main tank, which reduces the overall height. If you have one or more of these type transformers without desiccant air dryers, they should be installed.

## 4.3 Gaskets

Gaskets have several important jobs in sealing systems [6]. A gasket must create a seal and hold it over a long period of time. It must be impervious and not contaminate the insulating fluid or gas above the fluid. It should be easily removed and replaced. It must be elastic enough to flow into imperfections on the sealing surfaces. It must withstand high and low temperatures and remain resilient enough to hold the seal even with joint movement from expansion, contraction, and vibration. It must be resilient enough to not take a "set" even though exposed for a long time to pressure applied with bolt torque and temperature changes. It must have sufficient strength to resist crushing under applied load and resist blowout under system pressure or vacuum. It must maintain its integrity while being handled or installed. If a gasket fails to meet any of these criteria, a leak will result. Gasket leaks result from improper torque, choosing the wrong type gasket material, or the wrong size gasket. Improper sealing surface preparation or the gasket taking a "set" (becoming hard and losing its resilience and elasticity) will also cause a leak. Usually, gaskets take a set as a result of temperature extremes and age.

Sealing (mating) surface preparation: Clean the metal surface thoroughly. Remove all moisture, oil and grease, rust, etc. A wire brush and/or solvent may be required.
Caution: Take extra care that rust and dirt particles never fall into the transformer. The results could be catastrophic, when the transformer is energized.

After rust and scale have been removed, metal surfaces should be coated with Loctite Master gasket No. 518. This material will cure after you bolt up the gasket, so additional glue is not necessary. If the temperature is 50°F or more, you can bolt up the gasket immediately. This material comes in a kit (part No. 22424) with primer, a tube of material, and instructions. If these instructions are followed, the seal will last many years, and the gasket will be easy to remove later if necessary. If the temperature is under 50°F, wait about 1/2 to 1 hour after applying the material to surfaces before bolting. If you are using cork-nitrile or cork-neoprene, you can also seal gasket surfaces (including the edge of the gasket) with this same material.

Loctite makes other sealers that can be used to seal gaskets such as "Hi-tack".

GE glyptol No. 1201B-red can also be used to paint gasket and metal surfaces, but it takes more time and you must be more cautious about temperature. If possible, this work should be done in temperatures above 70°F to speed paint curing. Allow the paint to completely dry before applying glue or the new gasket. It is not necessary to remove old glyptol or other primer or old glue if the surface is fairly smooth and uniform.

Caution: Most synthetic rubber compounds, including nitrile (Buna N), contain some carbon, which makes it semi-conductive. Take extra care and never drop a gasket or pieces of gasket into a transformer tank. The results could be catastrophic when the transformer is energized.

Choose the correct replacement gasket. The main influences on gasket material selection are design of the gasket joint, maximum and minimum operating temperature, type of fluid contained, and internal pressure of the transformer.

Cork-nitrile should be used if the joint does not have grooves or limits. This material performs better than cork-neoprene because it does not take a set as easily and conforms better to mating surfaces. It also performs better at higher temperatures. Be extra careful when you store this material because it looks like cork-neoprene (described below), and they easily are mistaken for each other. Compression is the same as for cork-neoprene, about 45%. Cork-nitrile should recover 80% of its thickness with compression of 400 psi in accordance with ASTM F36. Hardness should be 60 to 75 durometer in accordance with ASTM D2240. (See published specifications for E-98 by manufacturer Dodge-Regupol Inc., Lancaster, PA.)

Caution: Cork-nitrile has a shelf life of only about 2 years, so do not order and stock more than can be used during this time.

Cork-Neoprene mixture (called coroprene) can also be used; however, it does not perform as well as cork-nitrile. This material takes a set when it is compressed and should only be used when there are no expansion limiting grooves. Using cork-neoprene in grooves can result in leaks from expansion and contraction of mating surfaces. The material is very porous and should be sealed on both sides and edges with a thin coat of Glyptol No. 1201B red or similar sealer before installing. Glyptol No. 1201B is a slow drying paint used to seal metal flanges and gaskets, and the paint should be allowed to dry totally before installation. Once compressed, this gasket should never be reused. These gaskets should be kept above 35°F before installation to prevent them from becoming hard. Gaskets should be cut and sealed (painted) indoors at temperatures above 70°F for ease of handling and to reduce paint curing time. Installing neoprene-cork gaskets when temperatures are at or near freezing should be avoided because the gasket could be damaged and leak. Cork-neoprene gaskets must be evenly compressed about 43 to 45%. For example, if the gasket is 1/4-inch thick, 0.43 x 0.25 = 0.10. When the gasket is torqued down, it should be compressed about 0.10 inch. Or you may subtract 0.1 from 1/4 inch to calculate the thickness of the gasket after it is compressed. In this case, 1/4 = 0.25 so 0.25 minus 0.10 = 0.15 inch would be the final distance between the mating surfaces after the gasket is compressed. In an emergency, if compression limits are required on this gasket, split lock washers may be used. Bend the washers until they are flat and install enough of them (minimum of three), evenly spaced, in the center of the gasket cross section to prevent excessive compression. The thickness of the washers should be such that the gasket compression is limited to approximately 43%, as explained above.

Nitrile "NBR" (Buna N) with 50 to 60 Duro (hardness) is generally the material that should be chosen for most transformer applications.

Caution: Do not confuse this material with Butyl Rubber. Butyl is not a satisfactory material for transformer gaskets. The terms Butyl and Buna are easily confused, and care must be taken to make sure Nitrile (Buna N) is always used and never Butyl.

Replace all cork neoprene gaskets with Nitrile if the joint has recesses or expansion limiting grooves. Be careful to protect Nitrile from sunlight; it is not sunlight resistant and will deteriorate, even if only the edges are exposed. It should not be greased when it is used in a non-movable (static) seal. When joints have to slide during installation or are used as a moveable seal (such as bushing caps, oil cooler isolation valves, and tap changer drive shafts), the gasket or O-ring should be lubricated with a thin coating of DOW No. 111 or No. 714 or equivalent grease. These are very thin and provide a good seal. Nitrile performs better than cork-neoprene; when exposed to higher temperatures, it will perform well up to 65 °C (150 °F).

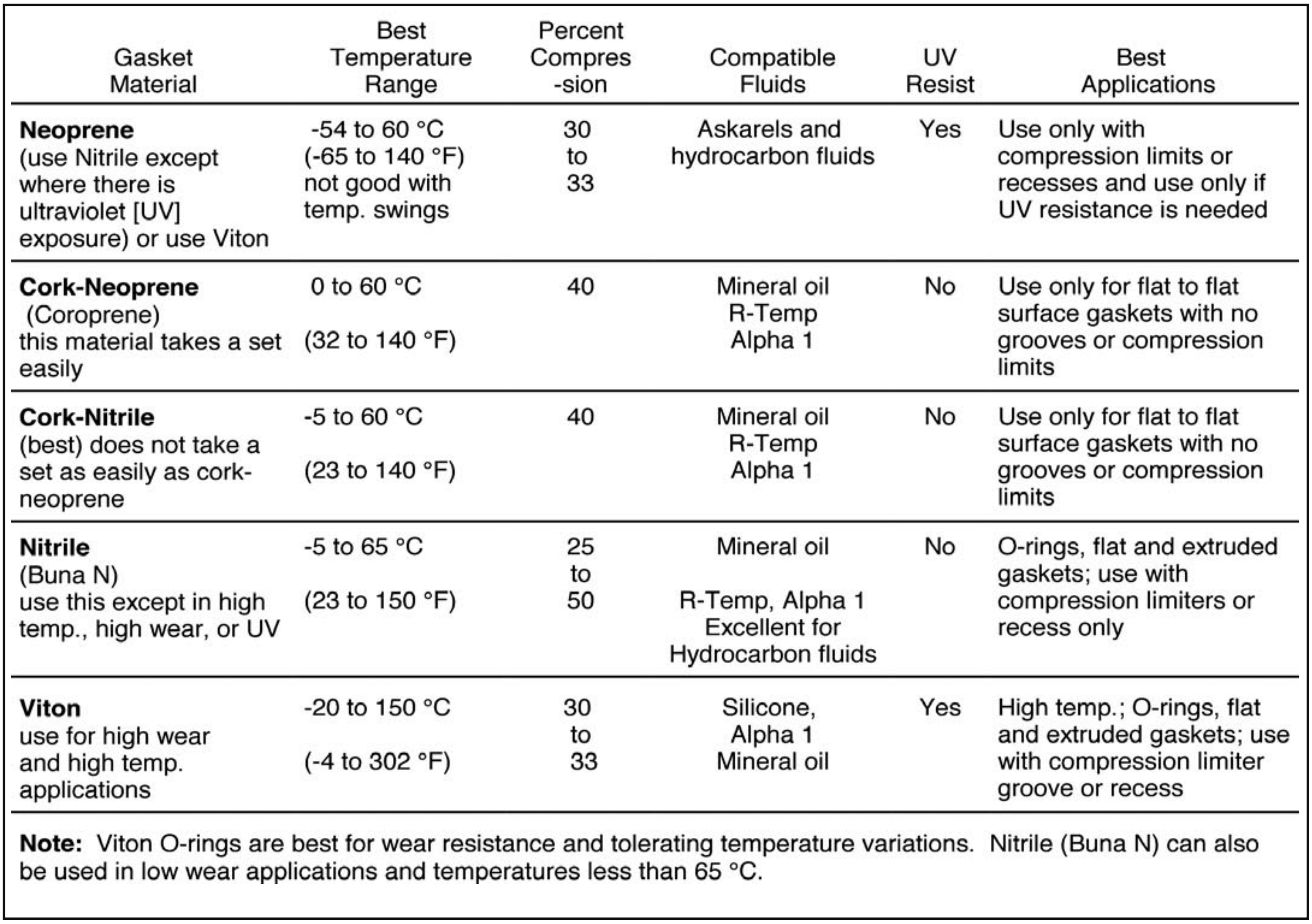
Viton should be used only for gaskets and O-rings in temperatures higher than 65°C or for applications requiring motion (shaft seals, etc.). Viton is very tough and wear resistant; however, it is very expensive ($1,000+ per sheet) and should not be used unless it is needed for high wear or high temperature applications. Viton should only be used with compression limiter grooves and recesses. Care should be taken to store Nitrile and Viton separately, or order them in different colors; the materials look alike and can be easily confused, and a much more expensive gasket can be installed unnecessarily. Compression and fill requirements for Viton are the as same as those for nitrile, outlined above and shown in table 1.

### Gasket sizing for standard groove depths.

Nitrile is chosen as the example because it is the most commonly used material for transformer gasketing. As shown in table 1, nitrile compression should be 25 to 50%. Nitrile sheets are available in 1/16-inch-thick increments.

Gasket thickness is determined by groove depth and standard gasket thickness. Choose the sheet thickness so that one-fourth to one-third of the gasket will protrude above the groove; this is the amount available to be compressed. (See table 2.) Gasket sheets come in standard thicknesses in 1/16-inch increments. Choose one that allows one-third of the gasket to stick out above the groove if you can, but never choose a thickness that allows less than one-fourth or as much as one-half to protrude above the groove. Do not try to remove old primer from the groove.

Table 1. - Transformer Gasket Application Summary



| Gasket Material | Best Temperature Range | Percent Compres -sion | Compatible Fluids | UV Resist | Best Applications |
|---|---|---|---|---|---|
| **Neoprene**<br>(use Nitrile except where there is ultraviolet [UV] exposure) or use Viton | -54 to 60 °C<br>(-65 to 140 °F)<br>not good with temp. swings | 30 to 33 | Askarels and hydrocarbon fluids | Yes | Use only with compression limits or recesses and use only if UV resistance is needed |
| **Cork-Neoprene**<br>(Coroprene)<br>this material takes a set easily | 0 to 60 °C<br>(32 to 140 °F) | 40 | Mineral oil<br>R-Temp<br>Alpha 1 | No | Use only for flat to flat surface gaskets with no grooves or compression limits |
| **Cork-Nitrile**<br>(best) does not take a set as easily as cork-neoprene | -5 to 60 °C<br>(23 to 140 °F) | 40 | Mineral oil<br>R-Temp<br>Alpha 1 | No | Use only for flat to flat surface gaskets with no grooves or compression limits |
| **Nitrile**<br>(Buna N)<br>use this except in high temp., high wear, or UV | -5 to 65 °C<br>(23 to 150 °F) | 25 to 50 | Mineral oil<br>R-Temp, Alpha 1<br>Excellent for Hydrocarbon fluids | No | O-rings, flat and extruded gaskets; use with compression limiters or recess only |
| **Viton**<br>use for high wear and high temp. applications | -20 to 150 °C<br>(-4 to 302 °F) | 30 to 33 | Silicone,<br>Alpha 1<br>Mineral oil | Yes | High temp.; O-rings, flat and extruded gaskets; use with compression limiter groove or recess |

**Note:** Viton O-rings are best for wear resistance and tolerating temperature variations. Nitrile (Buna N) can also be used in low wear applications and temperatures less than 65 °C.

Table 2. - Vertical Groove Compression for Circular Nitrile Gaskets

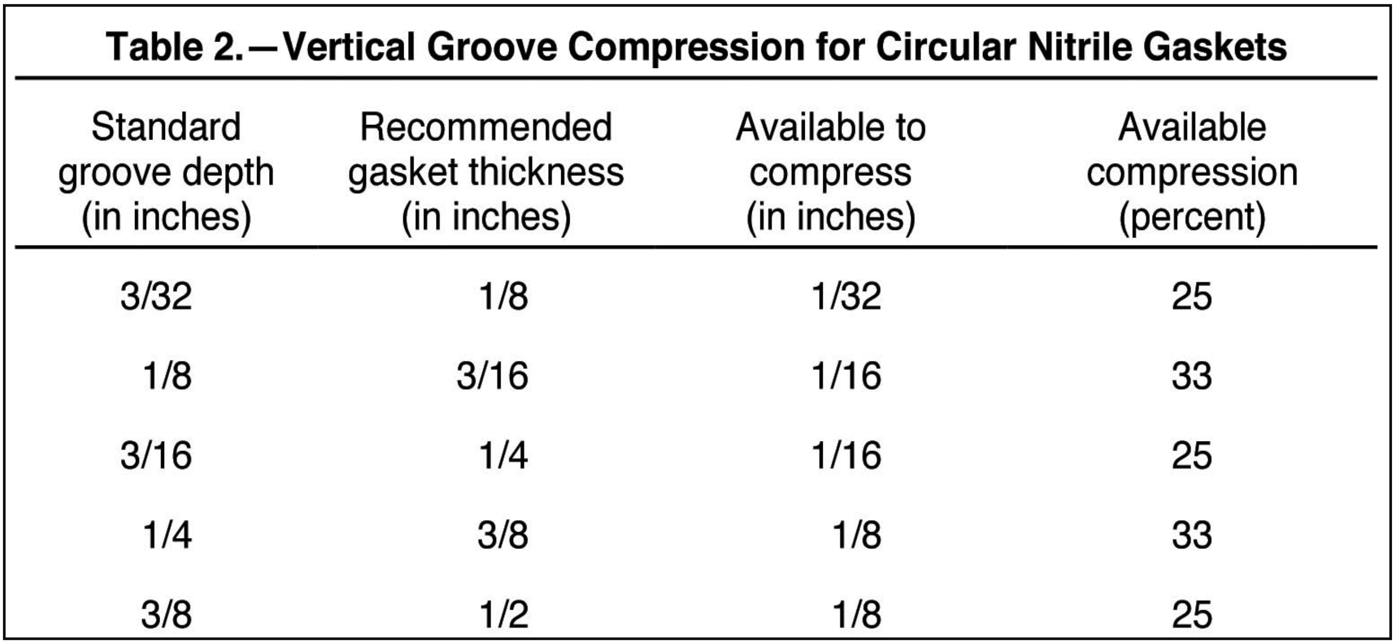


**Table 2.—Vertical Groove Compression for Circular Nitrile Gaskets**

| Standard groove depth (in inches) | Recommended gasket thickness (in inches) | Available to compress (in inches) | Available compression (percent) |
|---|---|---|---|
| 3/32 | 1/8 | 1/32 | 25 |
| 1/8 | 3/16 | 1/16 | 33 |
| 3/16 | 1/4 | 1/16 | 25 |
| 1/4 | 3/8 | 1/8 | 33 |
| 3/8 | 1/2 | 1/8 | 25 |

Horizontal groove fill is determined by how wide the groove is. The groove width is equal to the outer diameter (OD) minus the inner diameter (ID) divided by two:

$$\frac{od - ID}{2}$$

Or just measure the groove width with an accurate caliper.

The width of the groove minus the width of the gasket is the room left for the gasket to expand while being compressed. For nitrile, the amount of horizontal room needed is about 15 to 25%. Therefore, you need to cut the gasket cross-section so that it fills about 75 to 85% of the width of the groove.
For example, an 8-inch OD groove with a 6-inch ID

$$\frac{od-ID}{2} \quad \text{is} \quad \frac{8\text{-}6}{2} \quad = 1 \text{ inch}$$

Therefore, the width of the groove is 1 inch. Because we have to leave 25% expansion space, the width of the gasket is 75% of 1 inch, or 3/4 inch. So that the gasket can expand equally toward the center and toward the outside, you should leave one-half the expansion space at the inner diameter of the groove and one-half at the outer. In this example, there should be a total space of 25% of 1 inch or (1/4 inch) for expansion after the gasket is inserted, so you should leave 1/8-inch space at the OD and 1/8-inch space at the ID. See figure 14.

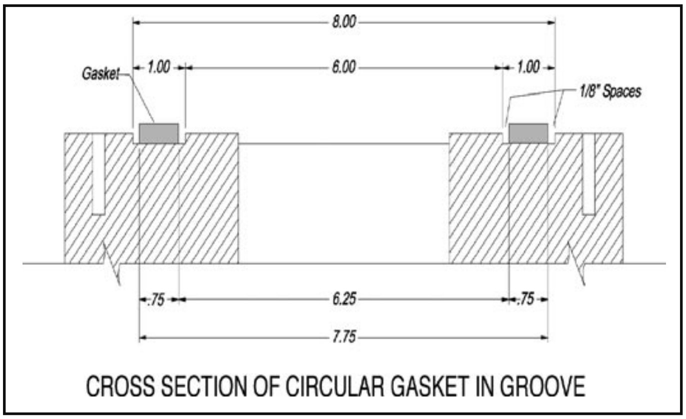


**Figure 14.—Cross Section of Circular Gasket in Groove.**

Always cut the outer diameter first. In this example, the outer diameter would be 8 inches minus 1/4 inch, or 7 3/4 inches.

Note: Since 1/8-inch space is required all around the gasket, 1/4 inch must be subtracted to allow 1/8 inch on both sides. The inner diameter would be 6 inches plus 1/4 inch or 6 1/4 inches. Note that 1/4 inch is subtracted from the OD but added to the ID.

To check yourself, subtract the inner radius from the outer to make sure you get the same gasket width calculated above. In this example, 3 7/8-inches (outer radius, 1/2 of 7 3/4), minus 3 1/8 inches (inner radius, 1/2 of 6 1/4), is 3/4 inch, which is the correct gasket width.

Rectangular Nitrile Gaskets larger than sheet stock on hand can be fabricated by cutting strips and corners with a table saw or a utility knife with razor blade. Cutting is easier if a little transformer oil or WD-40 oil is applied. Nitrile is also available in spools in standard ribbon sizes. The ends may be joined using a cyanoacrylate adhesive (super glue). There are many types of this glue; only a few of them work well with nitrile, and they all have a very limited shelf life. Remember to always keep them refrigerated to extend shelf life. The one proven to stand up best to temperature changes and compression is Lawson Rubber Bonder No. 92081. The Lawson part number is 90286, and it is available from Lawson Products Co. in Reno, Nevada, (702-856-1381). Loctite 404 is commonly available at NAPA auto parts stores and works also but does not survive temperature variations as well. Shelf life is critical. A new supply should always be obtained when a gasketing job is started; never use an old bottle that has been on the shelf since the last job.

When bonding the ends of ribbon together, ends should be cut at an angle (scarfed) at about 15 degrees. The best bond occurs when the length of the angle cut is about four times the thickness of the gasket. With practice, a craftsperson can cut 15-degree scarfs with a utility knife. A jig can also be made from wood to hold the gasket at a 15-degree angle for cutting and sanding. The ends may be further fine-sanded or ground on a fine bench grinder wheel to match perfectly before applying glue. A jig can be fabricated to hold the gasket at 15 degrees while cutting, sanding, or grinding.

**Table 3.—Vertical Groove Compression for Rectangular Nitrile Gaskets**

| Standard groove depth (in inches) | Standard ribbon width (in inches) | Recommended gasket thickness (in inches) | Available to compress (in inches) | Available compression (in inches) |
|---|---|---|---|---|
| 3/32 | 1/4 | 1/8 | 1/32 | 25 |
| 1/8 | 5/16 | 3/16 | 1/16 | 33 |
| 3/16 | 3/8 | 1/4 | 1/16 | 25 |
| 1/4 | 3/4 | 3/8 | 1/8 | 33 |
| 3/8 | 3/4 | 1/2 | 1/8 | 25 |

Note: Maximum horizontal fill of the groove should be 75 to 85% as explained above in the circular gasket section. However, it is not necessary to fill the groove fully to 75% to obtain a good seal. Choose the width of ribbon that comes close to, but does not exceed, 75 to 80%. If one standard ribbon width fills only 70% of the groove and the next size standard width fills 90%, choose the size that fills 70%. As in the circular groove explained above, place the gasket so that expansion space is equal on both sides. The key point is that the cross sectional area of the gasket remains the same as the cover is tightened; the thickness decreases, but the width increases. See below and figure 15.

Caution: Nitrile (Buna N) is a synthetic rubber compound and, as cover bolts are tightened, the gasket is compressed. Thickness of the gasket is decreased and the width is increased. If a gasket is too large, rubber will be pressed into the void between the cover and the sealing surface. This will prevent a metal-to-metal seal, and a leak will result. It is best if the cross sectional area of the gasket is a little smaller than the groove cross sectional area. As cover bolts are tightened, the thickness of the gasket decreases but the width increases so that cross sectional area (thickness times the width) remains the same. Care must be taken to ensure that the gasket cross sectional area is equal to or slightly smaller (never larger) than the groove cross sectional area. This will provide space for the rubber to expand in the groove so that it will not be forced out into the metal-to-metal contact area. (See figure 15.) If it is forced out into the "metal-to-metal" seal area, a leak generally will be the result. When this happens, our first response is to tighten the bolts, which bends the cover around the gasket material in the metal-to-metal contact area. The leak may stop (or more often not); but the next time the cover is removed, getting a proper seal is almost impossible because the cover is bent. Take extra care sizing the gasket, and these problems won't occur.

Caution: On some older bushings used on voltages 15 kV and above, it is necessary to install a semiconductive gasket. This type bushing (such as GE type L) has no ground connection between the bottom porcelain skirt flange and the ground ring. The bottom of the skirt is normally painted with a conductive paint, and then a semiconductive gasket is installed. This allows static electric charges to bleed off to ground. The gaskets are typically a semiconductive neoprene material. Sometimes, the gasket will have conductive metal staples near the center to bleed off these charges. When replacing this type gasket, always replace with like material. If like gasket material is not available, use cork-neoprene.

Thin metal conductive shim stock may be folded over the outer perimeter around approximately one-half the circumference. These pieces of shim stock should be evenly spaced around the circumference and stick far enough in toward the center so that they will be held when the bolts are tightened. As an example, if the gasket is 8 inches in diameter, the circumference would be πD or 3.1416 times 8 inches = 25.13 inches in circumference. Fifty percent of 25.13 is about 12 1/2 inches. Cut 12 strips 1-inch wide and long enough to be clamped by the flange top and bottom when tightened. Fold them over the outside edge of the gasket leaving a little more than 1-inch space between, so that the shim stock pieces will be more or less evenly spaced around the circumference.

Note: Failure to provide a path for static electric charges to get to ground will result in corona discharges between the ground sleeve and the bushing flange. The gasket will be rapidly destroyed, and a leak will be the result.

Bolting sequences to avoid sealing problems: If proper bolt tightening sequences are not followed or improper torque applied to the bolts, sealing problems will result. The resulting problem is illustrated in figure 16. A slight bow in the flange or lid top (exaggerated for illustration) occurs, which applies uneven pressure to the gasket.

This bow compromises the seal, and the gasket will eventually leak.

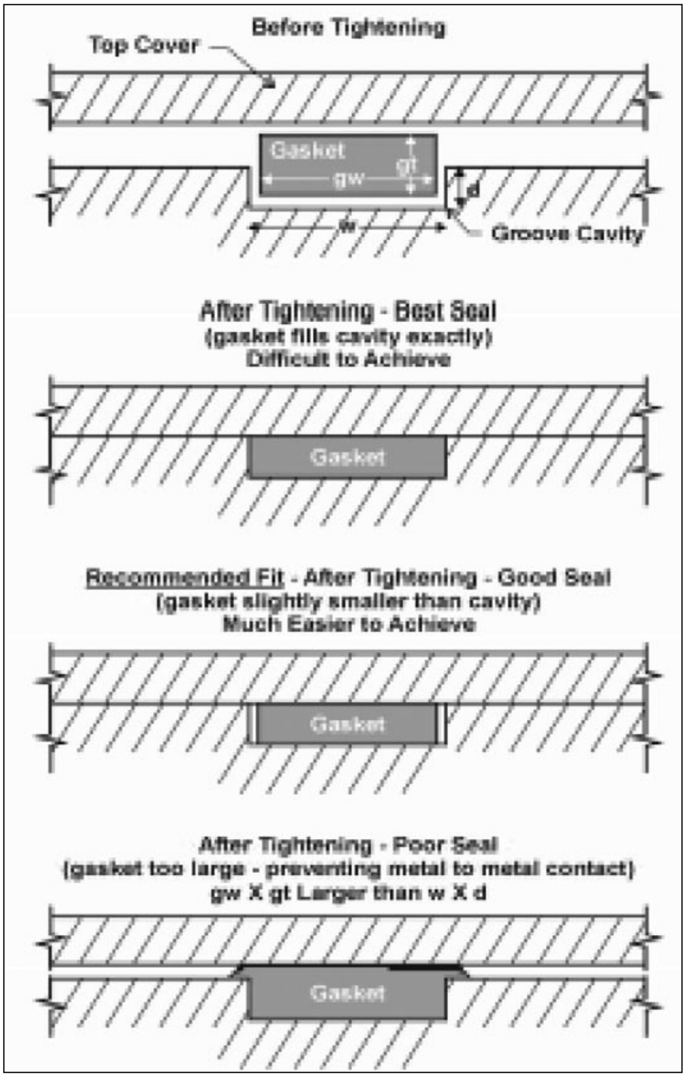

Before Tightening
Top Cover
Gasket
gw
gt
d
w
Groove Cavity
After Tightening - Best Seal
(gasket fills cavity exactly)
Difficult to Achieve
Gasket
Recommended Fit - After Tightening - Good Seal
(gasket slightly smaller than cavity)
Much Easier to Achieve
Gasket
After Tightening - Poor Seal
(gasket too large - preventing metal to metal contact)
gw X gt Larger than w X d
Gasket

**Figure 15.—Cross Section of Gasket Remains Constant Before Tightening and After. w x d = gw x gt**

Proper bolting sequences are illustrated for various type flanges/covers in figure 17.

Bolt numbers show the correct tightening sequences.

The numbers do not have to be followed exactly; however, the diagonal tightening patterns should be followed. By using proper torque and the illustrated sequence patterns, sealing problems from improper tightening and uneven pressure on the gasket can be avoided. Use a torque wrench and torque bolts according to the head stamp on the bolt. Check manufacturers instruction book for pancake gasket torque values.

## 4.4 Transformer Oils

### 4.4.1 Transformer Oil Functions.

Transformer oils perform at least four functions for the transformer. Oil provides insulation, provides cooling, and helps extinguish arcs. Oil also dissolves gases generated by oil degradation, moisture and gas from cellulose insulation, deterioration, and gases and moisture from whatever atmosphere the oil is exposed to. Close observation of dissolved gases in the oil, and other oil properties, provides the most valuable information about transformer health. Looking for trends by comparing information provided in several DGAs, and understanding its meaning, is the most important transformer diagnostic tool.

### 4.4.2 Dissolved Gas Analysis.

After 1 month of service and once each year, and more often if a problem is encountered, do a DGA. This is by far the most important tool for determining the health of a transformer.

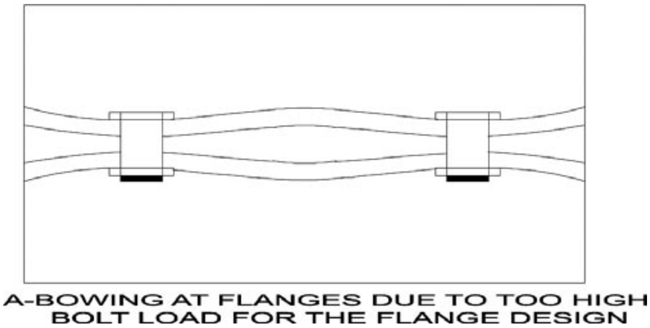

A-BOWING AT FLANGES DUE TO TOO HIGH
BOLT LOAD FOR THE FLANGE DESIGN

**Figure 16.—Bowing at Flanges.**

Caution: DGA is unreliable if the transformer is de-energized and has cooled, if the transformer is new, or if it has had less than 1 to 2 weeks of continuous service after oil processing.

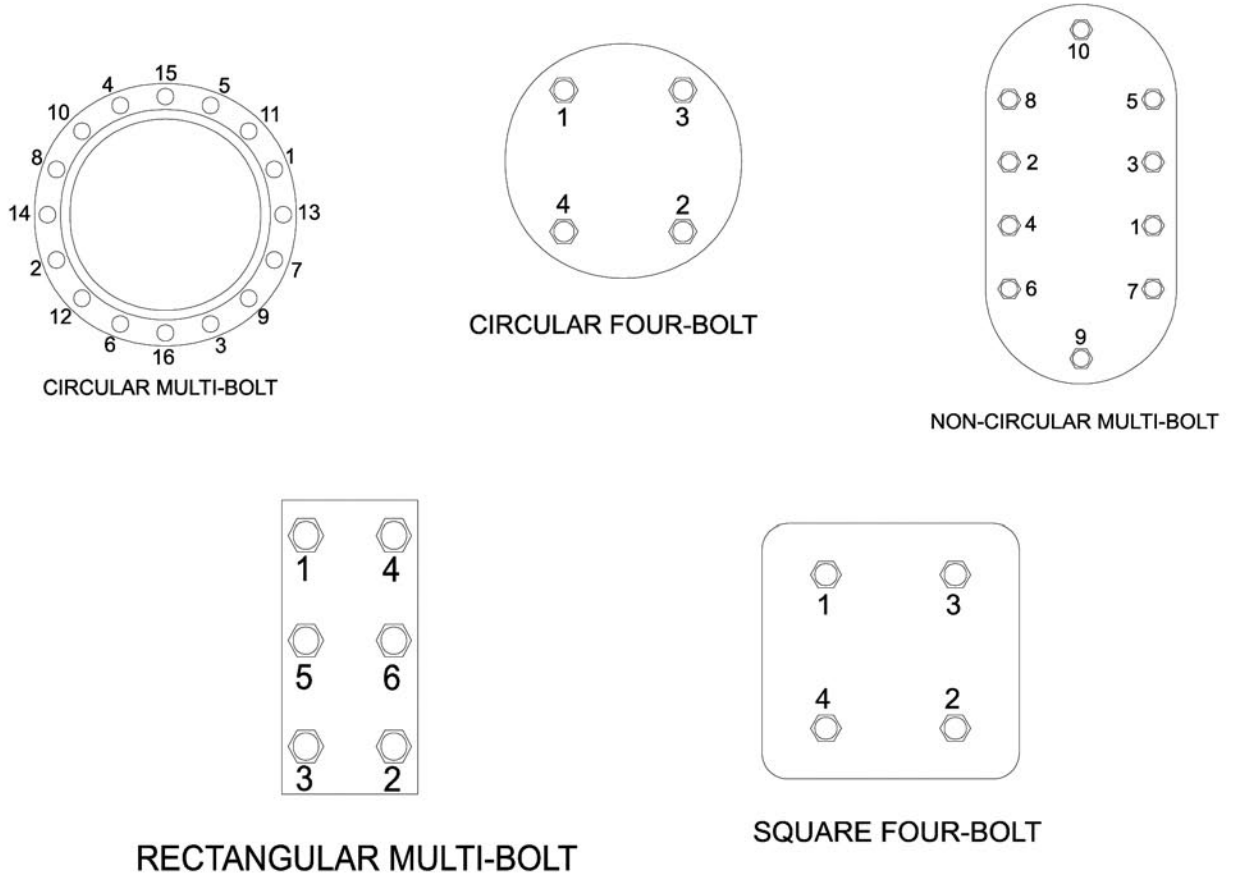
The purpose of this section is to provide guidance in interpreting DGA and to suggest actions based on the analysis. There are no "quick and sure" easy answers when dealing with transformers. Transformers are very complex, very expensive, and very important to Reclamation; and each one is different. Decisions must be based on experienced judgment founded on all available data and consultation with experienced people. Along with thorough periodic inspections covered earlier, the most important key to transformer life is periodic DGA and proper interpretation. Each DGA must be compared to prior DGAs so that trends can be recognized and rates of gas generation established.

**Although examples will be presented later, there is no universally accepted means for interpreting DGA** [15]. Transformers are very complex. Aging, chemical actions and reactions, electric fields, magnetic fields, thermal contraction and expansion, load variations, gravity, and other forces all interact inside the tank. Externally, through-faults, voltage surges, wide ambient temperature changes, and other forces such as the earth's magnetic field and gravity affect the transformer. There are few if any "cut and dried" DGA interpretations; even experts disagree. Consultation with others, experience, study, comparing earlier DGA's, keeping accurate records of a transformer's history, and noting information found when a transformer is disassembled will increase expertise and provide life extension to this critical equipment.

**Keeping accurate records** of each individual transformer is paramount. If a prior through-fault, overload, cooling problem, or nearby lightning strike has occurred, this information is extremely valuable when trying to determine what is going on inside the transformer. Baseline transformer test information should be established when the transformer is new or as soon as possible thereafter. This must include DGA, Doble, and other test results, discussed in the testing section, "4.7 Transformer Testing."

**4.4.3 Key Gas Method** of interpreting DGA is set forth in IEEE [11]. Key gases formed by degradation of oil and paper insulation are hydrogen ($H_2$), methane ($CH_4$), ethane ($C_2H_6$), ethylene ($C_2H_4$), acetylene ($C_2H_2$), carbon monoxide (CO), and oxygen ($O_2$). Except for carbon monoxide and oxygen, all these gases are formed from the degradation of the oil itself. Carbon monoxide, carbon dioxide ($CO_2$), and oxygen are formed from degradation of cellulose (paper) insulation. Carbon dioxide, oxygen, nitrogen ($N_2$), and moisture can also be absorbed from the air if there is a oil/air interface, or if there is a leak in the tank. Some of our transformers have a pressurized nitrogen blanket above the oil and, in these cases, nitrogen may be near saturation. (See table 4.) Gas type and amounts are determined by where the fault occurs in the transformer and the severity and energy of the event. Events range from low energy events such as partial discharge, which produces hydrogen and trace amounts of methane and ethane, to very high energy sustained arcing, capable of generating all the gases including acetylene, which requires the most energy.

4.4.4 Transformer Diagnosis Using Individual and Total Dissolved Key Gas Concentrations. A four-condition, DGA guide to classify risks to transformers with no previous problems has been developed by the IEEE [11]. The guide uses combinations of individual gases and total combustible gas concentration. This guide is not universally accepted and is only one of the tools used to evaluate transformers. The four conditions are defined on the next page:



CIRCULAR MULTI-BOLT

CIRCULAR FOUR-BOLT

NON-CIRCULAR MULTI-BOLT

RECTANGULAR MULTI-BOLT

SQUARE FOUR-BOLT

Figure 17.—Bolt Tightening Sequences.

Table 4.—Dissolved Key Gas Concentration Limits in Parts Per Million (ppm)

| Status | $H_2$ | $CH_4$ | $C_2H_2$ | $C_2H_4$ | $C_2H_6$ | CO | $CO_2$[1] | TDCG |
|---|---|---|---|---|---|---|---|---|
| Condition 1 | 100 | 120 | 35 | 50 | 65 | 350 | 2,500 | 720 |
| Condition 2 | 101-700 | 121-400 | 36-50 | 51-100 | 66-100 | 351-570 | 2,500-4,000 | 721-1,920 |
| Condition 3 | 701-1,800 | 401-1,000 | 51-80 | 101-200 | 101-150 | 571-1,400 | 4,001-10,000 | 1,921-4,630 |
| Condition 4 | >1,800 | >1,000 | >80 | >200 | >150 | >1,400 | >10,000 | >4,630 |

[1] $CO_2$ is not included in adding the numbers for TDCG because it is not a combustible gas.

**Condition 1:** Total dissolved combustible gas (TDCG) below this level indicates the transformer is operating satisfactorily. Any individual combustible gas exceeding specified levels in table 4 should have additional investigation.

**Condition 2:** TDCG within this range indicates greater than normal combustible gas level. Any individual combustible gas exceeding specified levels in table 4 should have additional investigation. A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas. (See table 5 for recommended sampling frequency and actions.)

**Condition 3:** TDCG within this range indicates a high level of decomposition of cellulose insulation and/or oil. Any individual combustible gas exceeding specified levels in table 4 should have additional investigation. A fault or faults are probably present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas. (See table 5.)

**Condition 4:** TDCG within this range indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer (table 5). Condition numbers for dissolved gases given in IEEE C-57-104-1991 (table 4) are extremely conservative. We have transformers that have operated safely with individual gases in Condition 4 with no problems; however, they are stable and gases are not increasing, or are increasing very slowly. If TDCG and individual gases are increasing significantly (more than 30 ppm/day), the fault is active and the transformer should be de-energized

**Table 5.—Actions Based on Dissolved Combustible Gas**

| Conditions | TDCG Level or Highest Individual Gas (See Table 4) | TDCG Generation Rates (PPM/Day) | Sampling Intervals and Operating Actions for Gas Generation Rates | |
|---|---|---|---|---|
| | | | Sampling Interval | Operating Procedures |
| Condition 1 | ≤720 ppm of TDCG or highest condition based on individual gas from table 4 | <10 | Annually: 6mo for EHV trans | Continue normal operation. |
| | | 10-30 | Quarterly | |
| | | >30 | Monthly | Exercise caution. Analyze individual gases to find cause. Determine load dependence. |
| Condition 2 | 721-1,920 ppm of TDCG or highest condition based on individual gas from table 4 | <10 | Quarterly | Exercise caution. Analyze individual gases to find cause. Determine load dependence. |
| | | 10-30 | Monthly | |
| | | >30 | Monthly | |
| Condition 3 | 1,941-2,630 ppm of TDCG or highest condition based on individual gas from table 4 | <10 | Monthly | Exercise extreme caution. Analyze individual gases to find cause. Plan outage. Call manufacturer and other consultants for advice. |
| | | 10-30 | Weekly | |
| | | >30 | Weekly | |
| Condition 4 | >4,630 ppm of TDCG or highest condition based on individual gas from table 4 | <10 | Weekly | Exercise extreme caution. Analyze individual gases to find cause. Plan outage. Call manufacturer and other consultants for advice. |
| | | 10-30 | Daily | |
| | | >30 | Daily | Consider removal from service. Call manufacturer and other consultants for advice. |

NOTES: 1. Either the **Highest Condition Based on Individual Gas** or **Total Dissolved Combustible Gas** can determine the condition (1,2,3, or 4) of the transformer [11]. For example, if the TDCG is between 1,941 ppm and 2,630 ppm, this indicates Condition 3. However ,if hydrogen is greater than 1,800 ppm, the transformer is in Condition 4, as shown in table 4..

2. When the table says "determine load dependence," this means, if possible, find out if the gas generation rate in ppm/day goes up and down with load. Perhaps the transformer is overloaded. Take oil samples every time the load changes; if load changes are too frequent, this may not be possible.

3. To get TDCG generation rate, divide the change in TDCG by the number of days between samples that the transformer has been loaded. Down-days should not be included. The individual gas generation rate ppm/day is determined by the same method.

when Condition 4 levels are reached.

A sudden increase in key gases and the rate of gas production is more important in evaluating a transformer than the amount of gas. One exception is acetylene (C2H2). The generation of any amount of this gas above a few ppm indicates high energy arcing.

Trace amounts (a few ppm) can be generated by a very hot thermal fault (500 °C). A one-time arc caused by a nearby lightning strike or a high-voltage surge can generate acetylene. If C2H2 is found in the DGA, oil samples should be taken weekly to determine if additional acetylene is being generated. If no additional acetylene is found and the level is below the IEEE Condition 4, the transformer may continue in service. However, if acetylene continues to increase, the transformer has an active high-energy internal arc and should be taken out of service. Further operation is extremely hazardous and may result in catastrophic failure. Operating a transformer with an active high-energy arc is extremely hazardous.

Table 4 assumes that no previous DGA tests have been made on the transformer or that no recent history exists. If a previous DGA exists, it should be reviewed to determine if the situation is stable (gases are not increasing significantly) or unstable (gases are increasing significantly). Deciding whether gases are increasing significantly depends on your particular transformer.

Compare the current DGA to older DGAs. If the production rate (ppm/day) of any one of the key gases and/or TDCG (ppm) has suddenly gone up, gases are probably increasing significantly. Refer to table 5, which gives suggested actions based on total amount of gas in ppm and rate of gas production in ppm/day.

Before going to table 5, determine transformer status from table 4; that is, look at the DGA and see if the transformer is in Condition 1, 2, 3, or 4. The condition for a particular transformer is determined by finding the highest level for any individual gas or by using the TDCG [11]. Either the individual gas or the TDCG can give the transformer a higher Condition number, which means it is at greater risk. If the TDCG number shows the transformer in Condition 3 and an individual gas shows the transformer in Condition 4, the transformer is in Condition 4. Always be conservative and assume the worst until proven otherwise.

## SAMPLING INTERVALS AND RECOMMENDED ACTIONS.

When sudden increases occur in dissolved gases, the procedures recommended in table 5 should be followed. Table 5 is paraphrased from table 3 in IEEE C57.104-1991. To make it easier to read, the order has been reversed with Condition 1 (lowest risk transformer) at the top and Condition 4 (highest risk) at the bottom. The table indicates the recommended sampling intervals and actions for various levels of TDCG in ppm.

An increasing gas generation rate indicates a problem of increasingseverity; therefore, as the generation rate (ppm/day) increases, a shorter sampling interval is recommended. (See table 5.)

Some information has been added to the table from IEEE C57-104-1991; that is, inferred from the text. To see the exact table, refer to the IEEE Standard.

If it can be determined what is causing gassing and the risk can be assessed, the sampling interval may be extended. For example, if the core is tested with a megohmmeter and an additional core ground is found, even though table 5 may recommend a monthly sampling interval, an operator may choose to lengthen the sampling interval, because the source of the gassing and generation rate is known.

A decision should never be made on the basis of just one DGA. It is very easy to contaminate the sample by accidentally exposing it to air. Mislabeling a sample is also a common cause of error. Mislabeling could occur when the sample is taken, or it could be accidentally contaminated or mishandled at the laboratory. Mishandling may allow some gases to escape to the atmosphere and other gases, such as oxygen, nitrogen, and carbon dioxide, to migrate from the atmosphere into the sample. If you notice a transformer problem from the DGA, the first thing to do is take another sample for comparison.

In the gas generation chart (figure 18) [13, 16] and discussion below, please note that temperatures at which gases form are only approximate. The figure is not drawn to scale and is only for purposes of illustrating temperature relationships, gas types, and quantities. These relationships represent what generally has been proven in controlled laboratory conditions using a mass spectrometer. This chart was used by R.R. Rogers of the Central Electric Generating Board (CEGB) of England to develop the "Rogers Ratio Method" of analyzing transformers (discussed later).

A vertical band at left shows what gases and approximate relative quantities are produced under partial discharge conditions. Note that all the gases are given off, but in much less quantity than hydrogen. It takes only a very low energy event (partial discharge/corona) to cause hydrogen molecules to form from the oil.

Gases are formed inside an oil-filled transformer similar to a petroleum refinery still, in that various gases begin forming at specific temperatures. From the Gas Generation Chart, we can see relative amounts of gas as well as approximate temperatures. Hydrogen and methane begin to form in small amounts around 150°C. Notice from the chart that beyond maximum points, methane (CH4), ethane and ethylene production goes down as temperature increases. At about 250°C, production of ethane (C2H6) starts. At about 350°C, production of ethylene (C2H4) begins. Acetylene (C2H2) starts between 500°C and 700 °C. In the past, the presence of only trace amounts of acetylene (C2H2) was considered to indicate a temperature of at least 700°C had occurred; however, recent discoveries have led to the conclusion that a thermal fault (hot spot) of 500°C can produce trace amounts (a few ppm). Larger amounts of acetylene can only be produced above 700°C by internal arcing. Notice that between 200°C and 300°C, the production of

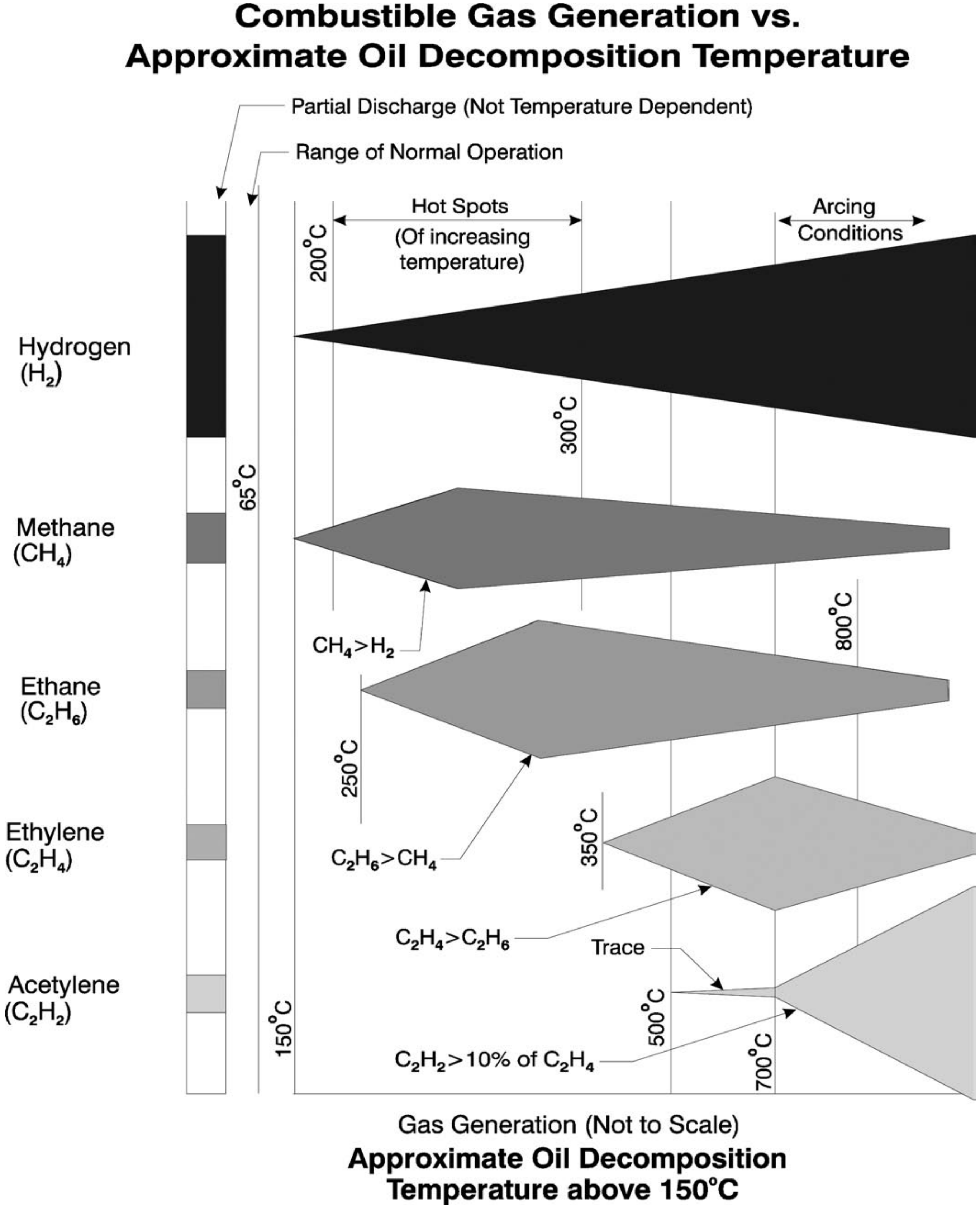


Figure 18.—Combustible Gas Generation Versus Temperature.

Table 6.—TOA L1 Limits and Generation Rate Per Month Alarm Limits

| GAS | L1 Limits | G1 Limits (ppm per month) | G2 Limits (ppm per month) |
|---|---|---|---|
| $H_2$ | 100 | 10 | 50 |
| $CH_4$ | 75 | 8 | 38 |
| $C_2H_2$ | 3 | 3 | 3 |
| $C_2H_4$ | 75 | 8 | 38 |
| $C_2H_6$ | 75 | 8 | 38 |
| CO | 700 | 70 | 350 |
| $CO_2$ | 7,000 | 700 | 3,500 |

methane exceeds hydrogen. Starting about 275°C and on up, the production of ethane exceeds methane. At about 450°C, hydrogen production exceeds all others until about 750°C to 800°C; then more acetylene is produced.

It should be noted that small amounts of H2, CH4, and CO are produced by normal aging. Thermal decomposition of oil-impregnated cellulose produces CO, CO2, H2, CH4, and O2. Decomposition of cellulose insulation begins at only about 100°C or less. Therefore, operation of transformers at no more than 90°C is imperative. Faults will produce internal "hot spots" of far higher temperatures than these, and the resultant gases show up in the DGA.

Table 6 is a chart of "fault types", parts which are paraphrased from the International Electrotechnical Commission (IEC 60599) [12]. This chart is not complete. It is impossible to chart every cause and effect due to the extreme complexity of transformers. DGA must be carefully examined with the idea of determining possible faults and possible courses of action. These decisions are based on judgment and experience and are seldom "cut and dried". Most professional associations agree that there are two basic fault types, thermal and electrical. The first three on the chart are electrical discharges, and the last three are thermal faults.

Ethane and ethylene are sometimes called "hot metal gases". When these gases are being generated and acetylene is not, the problem found inside the transformer normally involves hot metal. This may include bad contacts on the tap changer or a bad connection somewhere in the circuit, such as a main transformer lead. Stray flux impinging on the tank (such as in Westinghouse 7M series transformers) can cause these "hot metal gases". A shield has been known to become loose and fall and become ungrounded. Static can then build up and discharge to a grounded surface and produce "hot metal" gases. An unintentional core ground with circulating currents can also produce these gases. There are many other examples. Notice that both type faults (thermal and electrical) may be occurring at once, and one may cause the other. The associations do not mention magnetic faults; however, magnetic faults (such as stray magnetic flux impinging the steel tank or other magnetic structures) also cause hot spots.

Atmospheric gasses (N2, CO2, and O2) can be very valuable in a DGA in revealing a possible leak. However, as mentioned elsewhere, there are other reasons these gases are found in DGA. Nitrogen may have come from shipping the transformer with N2 inside or from a nitrogen blanket. CO2 and O2 are formed by degradation of cellulose. Be very careful; look at several DGAs, and see if atmospheric gases and possibly moisture levels are increasing. Also look at the transformer carefully if you can find an oil leak. Moisture and atmospheric gases will leak inside when the transformer is off and ambient temperature drops. (See section 4.3 on moisture)

Dissolved gas software. Several companies offer DGA computer software that diagnose transformer problems. These diagnoses must be used with engineering judgment and should never be taken at face value. The software is constantly changing. The Technical Service Center uses "Transformer Oil Analyst" (TOA) by Delta x Research. This software uses a composite of several current DGA methods. Dissolved gas analysis help is available from the TSC at D-8440 and D8450. Both groups have the above software and experience in diagnosing transformer problems.

One set of rules that TOA uses to generate alarms is based loosely on IEC 60599 (table 6). These rules are also very useful in daily dissolved gas analysis. They are based on L1 limits of IEC 60599 except for acetylene. IEC 60599 gives a range for L1 limits instead of a specific value. TOA uses the average in this range and then gives the user a "heads up" if a generation rate exceeds 10% of L1 limits per month. Acetylene is the exception; IEEE sets an L1 limit of 35 ppm (too high), and IEC sets acetylene range at 3 to 50. TOA picks the lowest number (3 ppm) and sets the generation rate alarm value at 3 ppm per month.

Notes: If one or more gas generation rates are equal to or exceed G1 limits (10% of L1 limits per month), you should begin to pay more attention to this transformer. Reduce the DGA sample interval, reduce loading, plan for future outage, contact the manufacturer etc.

If one or more combustible gas generation rates are equal to or exceed G2 limits (50% of L1 limits per month), this transformer should be considered in critical condition. You may want to reduce sample intervals to monthly or weekly, plan an outage, plan to rebuild or replace the transformer, etc. If an active arc is present (C2H2 generation), or if other heat gases are high (above Condition 4 limits in table 4), and G2 limits are exceeded, the transformer should be removed from service.

Table 7 is taken from IEC 60599 of key gases, possible faults, and possible findings. This chart is not all inclusive and should be used with other information. Additional possible faults are listed on following and preceding pages.

Transformers are so complex that it is impossible to put all symptoms and causes into a chart. Several additional transformer problems are listed below; there are many others.

1. Gases are generated by normal operation and aging, mostly H2 and CO with some CH4.

2. Operating transformers at sustained overload will generate combustible gases.

3. Problems with cooling systems, discussed in an earlier section, can cause overheating.

4. A blocked oil duct inside the transformer can cause local overheating, generating gases.

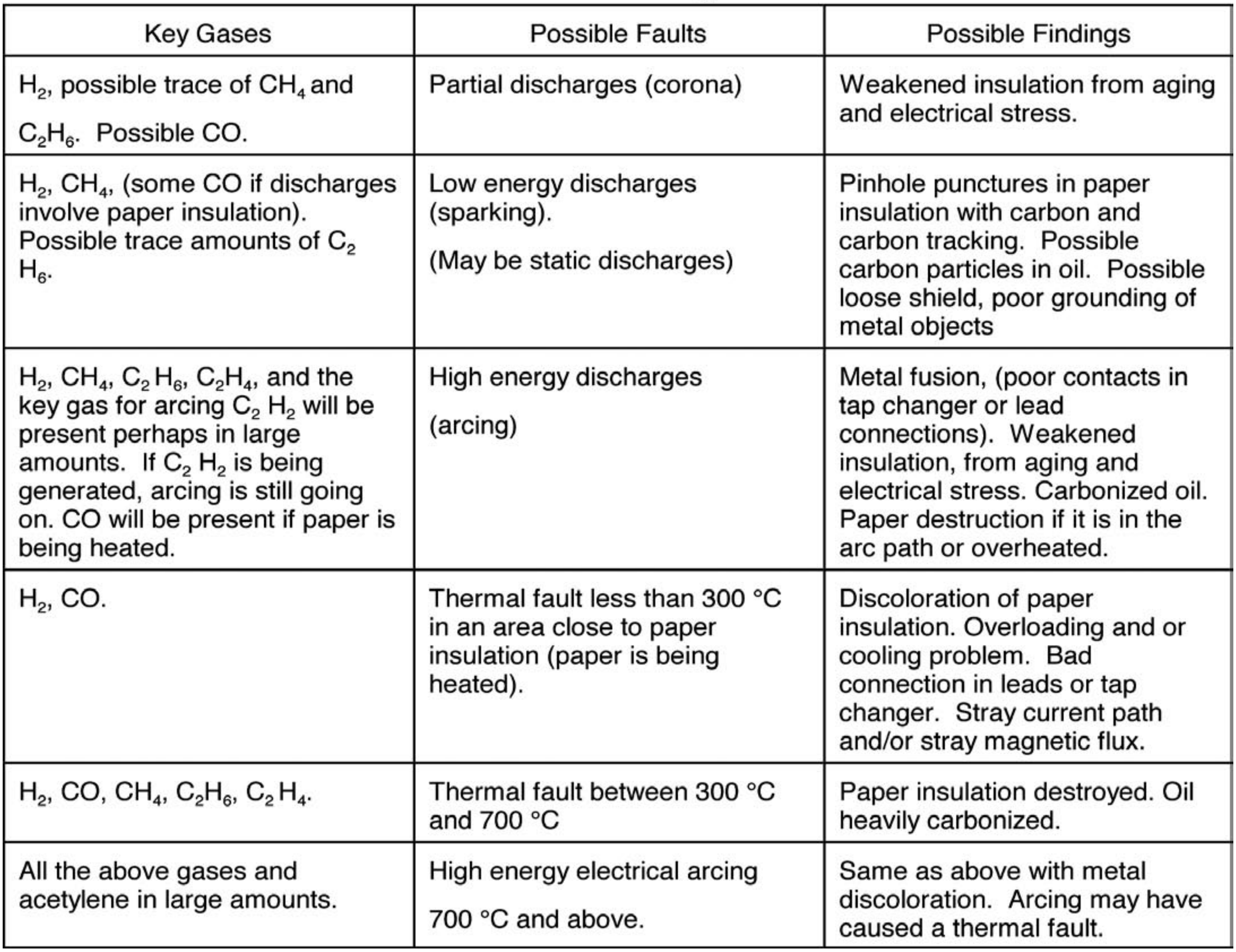
5. An oil directing baffle loose inside the transformer causes misdirection of cooling oil.

6. Oil circulating pump problems (bearing wear, impeller loose or worn) can cause transformer cooling problems.

7. Oil level is too low; this will not be obvious if the level indicator is inoperative.

8. Sludge in the transformer and cooling system. (See "3.

**Table 7.—Fault Types**



| Key Gases | Possible Faults | Possible Findings |
|---|---|---|
| $H_2$, possible trace of $CH_4$ and $C_2H_6$. Possible CO. | Partial discharges (corona) | Weakened insulation from aging and electrical stress. |
| $H_2$, $CH_4$, (some CO if discharges involve paper insulation). Possible trace amounts of $C_2H_6$. | Low energy discharges (sparking).<br>(May be static discharges) | Pinhole punctures in paper insulation with carbon and carbon tracking. Possible carbon particles in oil. Possible loose shield, poor grounding of metal objects |
| $H_2$, $CH_4$, $C_2H_6$, $C_2H_4$, and the key gas for arcing $C_2H_2$ will be present perhaps in large amounts. If $C_2H_2$ is being generated, arcing is still going on. CO will be present if paper is being heated. | High energy discharges<br>(arcing) | Metal fusion, (poor contacts in tap changer or lead connections). Weakened insulation, from aging and electrical stress. Carbonized oil. Paper destruction if it is in the arc path or overheated. |
| $H_2$, CO. | Thermal fault less than 300 °C in an area close to paper insulation (paper is being heated). | Discoloration of paper insulation. Overloading and or cooling problem. Bad connection in leads or tap changer. Stray current path and/or stray magnetic flux. |
| $H_2$, CO, $CH_4$, $C_2H_6$, $C_2H_4$. | Thermal fault between 300 °C and 700 °C | Paper insulation destroyed. Oil heavily carbonized. |
| All the above gases and acetylene in large amounts. | High energy electrical arcing<br>700 °C and above. | Same as above with metal discoloration. Arcing may have caused a thermal fault. |

Transformer Cooling Methods.")

9. Circulating stray currents may occur in the core, structure, and/or tank.

10. An unintentional core ground may cause heating by providing a path for stray currents.

11. A hot-spot can be caused by a bad connection in the leads or by a poor contact in the tap changer.

12. A hot-spot may also be caused by discharges of static electrical charges that build up on shields or core and structures which are not properly grounded.

13. Hot-spots may be caused by electrical arcing between windings and ground, between windings of different potential, or in areas of different potential on the same winding, due to deteriorated or damaged insulation.

14. Windings and insulation can be damaged by faults downstream (through faults), causing large current surges through the windings. Through faults cause extreme magnetic and physical forces that can distort and loosen windings and wedges. The result may be arcing in the transformer, beginning at the time of the fault, or the insulation may be weakened and arcing develop later.

15. Insulation can also be damaged by a voltage surge such as a nearby lightning strike or switching surge or closing out of step, which may result in immediate arcing or arcing that develops later.

16. Insulation may be deteriorated from age and simply worn out. Clearances and dielectric strength are reduced, allowing partial discharges and arcing to develop. This can also reduce physical strength allowing wedging and windings to move extensively during a through-fault, causing total mechanical and electrical failure.

17. High noise level (hum due to loose windings) can generate gas due to heat from friction. Compare the noise to sister transformers, if possible. Sound level meters are available at the TSC for diagnostic comparison and to establish baseline noise levels for future comparison.

Temperature. Gas production rates increase exponentially with temperature, and directly with volume of oil and paper insulation at high enough temperature to produce gases [11]. Temperature decreases as distance from the fault increases. Temperature at the fault center is highest, and oil and paper here will produce the most gas. As distance increases from the fault (hot spot), temperature goes down and the rate of gas generation also goes down. Because of the volume effect, a large heated volume of oil and paper will produce the same amount of gas as a smaller volume at a higher temperature [11]. We cannot tell the difference by looking at the DGA. This is one reason that interpreting DGAs is not an exact science.

**Gas Mixing.** Concentration of gases in close proximity to an active fault will be higher than in the DGA oil sample. As distance increases from a fault, gas concentrations decrease. Equal mixing of dissolved gases in the total volume of oil depends on time and oil circulation. If there are no pumps to force oil through radiators, complete mixing of gases in the total oil volume takes longer. With pumping and normal loading, complete mixing equilibrium should be reached within 24 hours and will have little effect on DGA if an oil sample is taken 24 hours or more after a problem begins.

**Table 8.—Dissolved Gas Solubility in Transformer Oil Accurate Only at STP, 25 °C (77 °F) and 14.7 psi (29.93 inches of mercury)**

| Dissolved Gas | Formula | Solubility in Transformer Oil (% by Volume) | Equivalent (ppm by Volume) | Primary Causes/Sources |
|---|---|---|---|---|
| Hydrogen[1] | $H_2$ | 7.0 | 70,000 | Partial discharge, corona, electrolysis of $H_2O$ |
| Nitrogen | $N_2$ | 8.6 | 86,000 | Inert gas blanket, atmosphere |
| Carbon Monoxide[1] | CO | 9.0 | 90,000 | Overheated cellulose, air pollution |
| Oxygen | $O_2$ | 16.0 | 160,000 | Atmosphere |
| Methane[1] | $CH_4$ | 30.0 | 300,000 | Overheated oil |
| Carbon Dioxide | $CO_2$ | 120.0 | 1,200,00 | Overheated cellulose, atmosphere |
| Ethane[1] | $C_2H_6$ | 280.0 | 2,800,00 | Overheated oil |
| Ethylene[1] | $C_2H_4$ | 280.0 | 2,800,000 | Very overheated oil |
| Acetylene[1] | $C_2H_2$ | 400.0 | 4,000,000 | Arcing in oil |

[1] Denotes combustible gas. Overheating can be caused both by high temperatures and by unusual or abnormal electrical stress.

**Gas Solubility.** Solubilities of gases in oil vary with temperature and pressure [13]. Solubility of all transformer gases vary proportionally up and down with pressure. Variation of solubilities with temperature is much more complex. Solubilities of hydrogen, nitrogen, carbon monoxide, and oxygen go up and down proportionally with temperature. Solubilities of carbon dioxide, acetylene, ethylene, and ethane are reversed and vary inversely with temperature changes. As temperature rises, solubilities of these gases go down; and as temperature falls, their solubilities increase. Methane solubility remains almost constant with temperature changes. Table 7 is accurate only at standard temperature and pressure (STP), (25 °C/77 °F) and (14.7 psi/29.93 inches of mercury, which is standard barometric pressure at sea level). Table 8 shows only relative differences in how gases dissolve in transformer oil.

From the solubility table (see table 8), comparing hydrogen with a solubility of 7% and acetylene with solubility of 400%, you can see that transformer oil has a much greater capacity for dissolving acetylene. However, 7% hydrogen by volume represents 70,000 ppm, and 400% acetylene represents 4,000,000 ppm. You will probably never see a DGA with numbers this high. Nitrogen can approach maximum level if there is a pressurized nitrogen blanket above the oil. Table 8 shows the maximum amount of each gas that the oil is capable of dissolving at standard temperature and pressure. At these levels, the oil is said to be saturated.

If you have conservator-type transformers and nitrogen, oxygen, and $CO_2$ are increasing, there is a good possibility the tank has a leak, or the oil may have been poorly processed. Check the diaphragm or bladder for leaks (section 4.2), and check for oily residue around the pressure relief device and other gasketed openings. There should be fairly low nitrogen and especially low oxygen in a conservator-type transformer. However, if the transformer was shipped new with pressurized nitrogen inside and has not been degassed properly, there may be high nitrogen content in the DGA, but the nitrogen level should not be increasing after the transformer has been in service for a few years. When oil is being installed in a new transformer, a vacuum is placed on the tank which pulls out nitrogen and pulls in the oil. Oil is free to absorb nitrogen at the oil/gas interface, and some nitrogen may be trapped in the windings, paper insulation, and structure. In this case, nitrogen may be fairly high in the DGAs. However, oxygen should be very low, and nitrogen should not be increasing. It is important to take an oil sample early in the transformer's service life to establish a baseline DGA; then take samples at least annually. The nitrogen and oxygen can be compared with earlier DGAs; and if they increase, it is a good indication of a leak. If the transformer oil has ever been degassed, nitrogen and oxygen should be low in the DGA. It is extremely important to keep accurate records over a transformer's life; when a problem occurs, recorded information helps greatly in troubleshooting.

**4.4.5 Rogers Ratio Method of DGA.** Rogers Ratio Method of DGA [18] is an additional tool that may be used to look at dissolved gases in transformer oil. Rogers Ratio Method compares quantities of different key gases by dividing one into the other. This gives a ratio of the amount of one key gas to another. By looking at the Gas Generation Chart (figure 18), you can see that, at certain temperatures, one gas will be generated more than another gas. Rogers used these relationships and determined that if a certain ratio existed, then a specific temperature had been reached. By comparing a large number of transformers with similar gas ratios and data found when the transformers were examined, Rogers could then say that certain faults were present. Like the Key Gas Analysis above, this method is not a "sure thing" and is only an additional tool to use in analyzing transformer problems. Rogers Ratio Method, using three-key gas ratios, is based on earlier work by Doerneburg, who used five-key gas ratios. Ratio methods are only valid if a significant amount of the gases used in the ratio is present. A good rule is: Never make a decision based only on a ratio if either of the two gases used in a ratio is less than 10 times the amount the gas chromatograph can detect (12). (Ten times the individual gas detection limits are shown in table 9 and below.) This rule makes sure that instrument inaccuracies have little effect on the ratios. If either of the gases are lower than 10 times the detection limit, you most likely do not have the particular problem that this ratio deals with anyway. If the gases are not at least 10 times these limits, this does not mean you cannot use the Rogers Ratios; it means that the results are not as certain as if the gases were at least at these levels. This is another reminder that DGAs are not an exact science and there is no "one best easy way" to analyze transformer problems. Approximate detection limits are as follows, depending on the lab and equipment:

**Dissolved Gas Analysis Detection Limits.**
Hydrogen ($H_2$) about 5 ppm
Methane ($CH_4$) about 1 ppm
Acetylene ($C_2H_2$) about 1 to 2 ppm
Ethylene ($C_2H_4$) about 1 ppm
Ethane ($C_2H_6$) about 1 ppm
Carbon monoxide (CO) and carbon cioxide ($CO_2$) about 25 ppm
Oxygen ($O_2$ ) and nitrogen ($N_2$) about 50 ppm

When a fault occurs inside a transformer, there is no problem with minimum gas amounts at which the ratio are valid. There will be more than enough gas present.

If a transformer has been operating normally for some time and a DGA shows a sudden increase in the amount of gas, the first thing to do is take a second sample to verify there is a problem. Oil samples are easily contaminated during sampling or at the lab. If the next DGA shows gases to be more in line with prior DGAs, the earlier oil sample was contaminated, and there is no further cause for concern. If the second sample also shows increases in gases, the problem is real. To apply Ratio Methods, it helps to subtract gases that were present prior to sudden gas increases. This takes out gases that have been generated up to this point due to normal aging and from prior problems. This is especially true for ratios using $H_2$ and the cellulose insulation gases CO and $CO_2$ [12]. These are generated by normal aging.

**Rogers Ratio Method Uses the Following Three Ratios.**

$C_2H_2/C_2H_4$, $CH_4/H_2$, $C_2H_4/C_2H_6$

These ratios and the resultant fault indications are based on large numbers of DGAs and transformer failures and what was discovered after the failures.

There are other ratio methods, but only the Rogers Ratio Method will be discussed since it is the one most commonly used. The method description is paraphrased from Rogers' original paper [18] and from IEC 60599 [12].

Caution: Rogers Ratio Method is for fault analyzing, not for fault detection. You must have already decided that you have a problem from the total amount of gas (using IEEE limits) or

Table 9.—Rogers Ratios for Key Gases

| Code range of ratios | $\frac{C_2H_2}{C_2H_4}$ | $\frac{CH_4}{H_2}$ | $\frac{C_2H_4}{C_2H_6}$ | Detection limits and 10 x detection limits are shown below: | | |
|---|---|---|---|---|---|---|
| <0.1 | 0 | 1 | 0 | $C_2H_2$ | 1 ppm | 10 ppm |
| 0.1-1 | 1 | 0 | 0 | $C_2H_4$ | 1 ppm | 10 ppm |
| 1-3 | 1 | 2 | 1 | $CH_4$ | 1 ppm | 10 ppm |
| >3 | 2 | 2 | 2 | $H_2$ | 5 ppm | 50 ppm |
| | | | | $C_2H_6$ | 1 ppm | 10 ppm |

| Case | Fault Type | $\frac{C_2H_2}{C_2H_4}$ | $\frac{CH_4}{H_2}$ | $\frac{C_2H_4}{C_2H_6}$ | Problems Found |
|---|---|---|---|---|---|
| 0 | No fault | 0 | 0 | 0 | Normal aging |
| 1 | Low energy partial discharge | 1 | 1 | 0 | Electric discharges in bubbles, caused by insulation voids or super gas saturation in oil or cavitation (from pumps) or high moisture in oil (water vapor bubbles). |
| 2 | High energy partial discharge | 1 | 1 | 0 | Same as above but leading to tracking or perforation of solid cellulose insulation by sparking, or arcing; this generally produces CO and $CO_2$. |
| 3 | Low energy discharges, sparking, arcing | 1-2 | 0 | 1-2 | Continuous sparking in oil between bad connections of different potential or to floating potential (poorly grounded shield etc); breakdown of oil dielectric between solid insulation materials. |
| 4 | High energy discharges, arcing | 1 | 0 | 2 | Discharges (arcing ) with power follow through; arcing breakdown of oil between windings or coils, or between coils and ground, or load tap changer arcing across the contacts during switching with the oil leaking into the main tank. |
| 5 | Thermal fault less than 150 °C (see note 2) | 0 | 0 | 1 | Insulated conductor overheating; this generally produces CO and $CO_2$ because this type of fault generally involves cellulose insulation. |
| 6 | Thermal fault temp. range 150-300 °C (see note 3) | 0 | 2 | 0 | Spot overheating in the core due to flux concentrations.<br>Items below are in order of increasing temperatures of hot spots. Small hot spots in core. Shorted laminations in core. Overheating of copper conductor from eddy currents. Bad connection on winding to incoming lead, or bad contacts on load or no-load tap changer. Circulating currents in core; this could be an extra core ground, (circulating currents in the tank and core); this could also mean stray flux in the tank.<br>These problems may involve cellulose insulation which will produce CO and $CO_2$. |
| 7 | Thermal fault temp. range 300-700 °C | 0 | 2 | 1 | |
| 8 | Thermal fault temp. range over 700 °C (see note 4) | 0 | 2 | 2 | |

**Notes:** 1. There will be a tendency for ratio $C_2H_2/C_2H_4$ to rise from 0.1 to above 3 and the ratio $C_2H_4/C_2H_6$ to rise from 1-3 to above 3 as the spark increases in intensity. The code at the beginning stage will then be 1 0 1.

2. These gases come mainly from the decomposition of the cellulose which explains the zeros in this code.

3. This fault condition is normally indicated by increasing gas concentrations. $CH_4/H_2$ is normally about 1, the actual value above or below 1, is dependent on many factors such as the oil preservation system (conservator, $N_2$ blanket, etc.), the oil temperature, and oil quality.

4. Increasing values of $C_2H_2$ (more than trace amounts), generally indicates a hot spot higher than 700 °C. This generally indicates arcing in the transformer. If acetylene is increasing and especially if the generation rate is increasing, the transformer should be deenergized, further operation is extremely hazardous.

***General Remarks:***

1. Values quoted for ratios should be regarded as typical (not absolute). This means that the ratio numbers are not "carved in stone"; there may be transformers with the same problems whose ratio numbers fall outside the ratios shown at the top of the table.

2. Combinations of ratios not included in the above codes may occur in the field. If this occurs, the Rogers Ratio Method will not work for analyzing these cases.

3. Transformers with on-load tap changers may indicate faults of code type 2 0 2 or 1 0 2 depending on the amount of oil interchange between the tap changer tank and the main tank.

## Example 1

**Example** of a Reclamation transformer DGA:

| | |
|---|---|
| Hydrogen ($H_2$) | 9 ppm |
| Methane ($CH_4$) | 60 |
| Ethane ($C_2H_6$) | 53 |
| Ethylene ($C_2H_4$) | 368 |
| Acetylene ($C_2H_2$) | 3 |
| Carbon Monoxide (CO) | 7 |
| Carbon Dioxide ($CO_2$) | 361 |
| Nitrogen ($N_2$) | 86,027 |
| Oxygen ($O_2$) | 1,177 |
| TDCG | 500 |

**Rogers Ratio Analysis**

| | Code |
|---|---|
| $C_2H_2/C_2H_4 = 3/368 = 0.00815$ | 0 |
| $CH_4/H_2 = 60/9 = 6.7$ | 2 |
| $C_2H_4/C_2H_6 = 368/53 = 6.9$ | 2 |

This code combination is Case 8 in table 4, which indicates this transformer has a thermal fault hotter than 700 °C.

Ethylene and ethane are sometimes called "hot metal gases". Notice this fault does not involve paper insulation, because CO is very low. $H_2$ and $C_2H_2$ are both less than 10 times the detection limit. This means the diagnosis does not have a 100% confidence level of being correct. However, due to the high ethylene, the fault is probably a bad connection where an incoming lead is bolted to a winding lead, or perhaps bad tap changer contacts, or additional core ground (large circulating currents in the tank and core). See the two bottom problems on table 10 later in this chapter. This example was chosen to show a transformer that was not a "clear cut" diagnosis. Engineering judgment is always required.

A small quantity of acetylene is present, just above the detection limit of 1 ppm. This is not high energy arcing due to the small amount; it has more likely been produced by a one-time nearby lightning strike or a voltage surge.

## Example 2

| | Latest DGA | Prior DGA No. 2 | Prior DGA No. 1 |
|---|---|---|---|
| Hydrogen ($H_2$) | 26 ppm | 27 | 17 |
| Methane ($CH_4$) | 170 | 164 | 157 |
| Ethane ($C_2H_6$) | 278 | 278 | 156 |
| Ethylene ($C_2H_4$) | 25 | 4 | 17 |
| Acetylene ($C_2H_2$) | 2 | 0 | 0 |
| Carbon Monoxide (CO) | 92 | 90 | 96 |
| Carbon Dioxide ($CO_2$) | 3,125 | 2,331 | 2,476 |
| Nitrogen ($N_2$) | 67,175 | 72,237 | 62,641 |
| Oxygen ($O_2$) | 608 | 1,984 | 440 |

### Rogers Ratio Analysis Based on Latest DGA:

| | | | Codes |
|---|---|---|---|
| $C_2H_2/C_2H_4$ | = 2/25 | = 0.080 | 0 |
| $CH_4/H_2$ | = 170/26 | = 6.54 | 2 |
| $C_2H_4/C_2H_6$ | = 25/278 | = 0.09 | 0 |

increased gas generation rates. Rogers Ratios will only give you an indication of what the problem is; it cannot tell you whether or not you have a problem. If you already suspect a problem based on total combustible gas levels or increased rate-of-generation, then you will normally already have enough gas for this method to work. A good system to determine whether you have a problem is to use table 5 in the Key Gas Method. If two or more of the key gases are in condition two and the gas generation is at least 10% per month of the L1 limit, you have a problem. Also, for the diagnosis to be valid, gases used in ratios should be at least 10 times the detection limits given earlier. The more gas you have, the more likely the Rogers Ratio Method will give a valid diagnosis. The reverse is also true; the less gas you have, the less likely the diagnosis will be valid. If a gas used in the denominator of any ratio is zero, or is shown in the DGA as not detected (ND), use the detection limit of that particular gas as the denominator. This gives a reasonable ratio to use in diagnostic table 9. Zero codes mean that you do not have a problem in this area.

Ethylene and ethane are sometimes called "hot metal gases". Notice this fault does not involve paper insulation, because CO is very low. H2 and C2 H2 are both less than 10 times the detection limit. This means the diagnosis does not have a 100% confidence level of being correct. However, due to the high ethylene, the fault is probably a bad connection where an incoming lead is bolted to a winding lead, or perhaps bad tap changer contacts, or additional core ground (large circulating currents in the tank and core). See the two bottom problems on table 10 later in this chapter. This example was chosen to show a transformer that was not a "clear cut" diagnosis. Engineering judgment is always required.

A small quantity of acetylene is present, just above the detection limit of 1 ppm. This is not high energy arcing due to the small amount; it has more likely been produced by a one-time nearby lightning strike or a voltage surge.

Notice that methane is increasing slowly, but ethane had a large increase between samples 1 and 2 but did not increase between samples 2 and 3. Note that two key gases (CH2 and C2H6) are above IEEE Condition 1 in table 5, so the Rogers Ratio Method is valid. By referring to table 9, this combination of codes is Case 6, which indicates the transformer has a thermal fault in the temperature range of 150°C to 300°C.

Life history of the transformer must be examined carefully. It is, again, very important to keep accurate records of every transformer. This information is invaluable when it becomes necessary to do an evaluation.

The transformer in this example is one of three sister transformers that have had increased cooling installed and are running higher loads due to a generator upgrade several years ago. Transformer sound level (hum) is markedly higher than for the two sister transformers. The unit breaker experienced a fault some years ago, which placed high mechanical stresses on the transformer. This generally means loose windings, which can generate gas due to friction (called a thermal fault) by Rogers Ratios. Comparison with sister units reveals almost triple the ethane as the other two, and it is above the IEEE Condition 4.Gases are increasing slowly; there has been no sudden rate increase in combustible gas production. Notice the large increase in O2 and N2 between the first and second DGA and the large decrease between the second and third. This probably means that the oil sample was exposed to air (atmosphere) and that these two gases are inaccurate in the middle sample.

Carbon Dioxide Carbon Monoxide Ratio. This ratio is not included in the Rogers Ratio Method of analysis. However, it is useful to determine if a fault is affecting the cellulose insulation. This ratio is included in transformer oil analyzing software programs such as Delta X Research Transformer Oil Analyst. This analysis is available from the TSC at D-8440 and D-8450 in Denver.

Formation of CO2 and CO from the degradation of oil impregnated paper increases rapidly with temperature. CO2/CO ratios less than three are generally considered an indication of probable paper involvement in an electrical fault (arcing or sparking), along with some carbonization of paper. Normal CO2 /CO ratios are typically around seven. Ratios above 10 generally indicate a thermal fault with the involvement of cellulose. This is only true if the CO2 came from within the transformer (no leaks), and these ratios are only meaningful if there is a significant amount of both gases. Caution must be employed because oil degradation also produces these gases, and CO2 can also be dissolved in the oil from atmospheric leaks. The oil sample can also pick up CO 2 and O2 if it is exposed to air during sampling or handling at the lab. If a fault is suspected, look carefully to see if CO is increasing. If CO is increasing around 70 ppm or more per month (generation limit from IEC 60599), there is probably a fault. It is a good idea to subtract the amount of CO and CO2 shown before the increase in CO and CO2 began, so that only gases caused by the present fault are used in the ratio. This will eliminate CO and CO2 generated by normal aging and other sources. When excessive cellulose degradation is suspected (CO2 /CO ratios less than 3, or greater than 10), it may be advisable to ask for a furan analysis with the next DGA. This will give an indication of useful life left in the paper insulation [12].

You cannot de-energize a transformer based on furan analysis alone. All this test does is give an indication of the health of the paper; it is not a sure thing. But furan analysis is recommended by many experts to give an indication of remaining life when the CO2 /CO ratio is less than 3 or greater than 10. Some oil laboratories do this test on a routine basis, and some charge extra for it.

Table 10 is adapted from IEC 60599 Appendix A.1.1 [12]. Some of the wording has been changed to reflect American language usage rather than European.

### 4.5 MOISTURE PROBLEMS

Moisture, especially in the presence of oxygen, is extremely hazardous to transformer insulation. Each DGA and Doble test result should be examined carefully to see if water is increasing and to determine the moisture by dry weight (M/DW) or percent saturation that is in the paper insulation. When 2% M/DW is reached, plans should be made for a dry out. Never allow the M/DW to go above 2.5% in the paper or 30% oil saturation without drying out the transformer. Each time the moisture is doubled in a transformer, the life of the insulation is cut by one-half. Keep in mind that the life of the transformer is the life of

**Table 10.—Typical Faults in Power Transformers**

| Fault | Examples |
|---|---|
| Partial discharges | Discharges in gas-filled cavities in insulation, resulting from incomplete impregnation, high moisture in paper, gas in oil supersaturation or cavitation, (gas bubbles in oil) leading to X wax formation on paper. |
| Discharges of low energy | Sparking or arcing between bad connections of different floating potential, from shielding rings, toroids, adjacent discs or conductors of different windings, broken brazing, closed loops in the core. Additional core grounds. Discharges between clamping parts, bushing and tank, high voltage and ground, within windings. Tracking in wood blocks, glue of insulating beam, winding spacers. Dielectric breakdown of oil, load tap changer breaking contact. |
| Discharges of high energy | Flashover, tracking or arcing of high local energy or with power follow-through. Short circuits between low voltage and ground, connectors, windings, bushings, and tank, windings and core, copper bus and tank, in oil duct. Closed loops between two adjacent conductors around the main magnetic flux, insulated bolts of core, metal rings holding core legs. |
| Overheating less than 300 °C | Overloading the transformer in emergency situations. Blocked or restricted oil flow in windings. Other cooling problem, pumps valves, etc. See the “Cooling” section in this document. Stray flux in damping beams of yoke. |
| Overheating<br>300 to 700 °C | Defective contacts at bolted connections (especially busbar), contacts within tap changer, connections between cable and draw-rod of bushings.<br>Circulating currents between yoke clamps and bolts, clamps and laminations, in ground wiring, bad welds or clamps in magnetic shields.<br>Abraded insulation between adjacent parallel conductors in windings. |
| Overheating over 700 °C | Large circulating currents in tank and core. Minor currents in tank walls created by high uncompensated magnetic field. Shorted core laminations. |

**Notes:**

1. X wax formation comes from Paraffinic oils (paraffin based). These are not used in transformers at present in the United States but are predominate in Europe.
2. The last overheating problem in the table says "over 700 °C." Recent laboratory discoveries have found that acetylene can be produced in trace amounts at 500 °C, which is not reflected in this table. We have several transformers that show trace amounts of acetylene that are probably not active arcing but are the result of high-temperature thermal faults as in the example. It may also be the result of one arc, due to a nearby lightning strike or voltage surge.
3. A bad connection at the bottom of a bushing can be confirmed by comparing infrared scans of the top of the bushing with a sister bushing. When loaded, heat from a poor connection at the bottom will migrate to the top of the bushing, which will display a markedly higher temperature. If the top connection is checked and found tight, the problem is probably a bad connection at the bottom of the bushing.

Table 11.—Comparison of Water Distribution in Oil and Paper [5]

| Temperature (degrees C) | Water in Oil | Water in Paper |
|---|---|---|
| 20° | 1 | 3,000 times what is in the oil |
| 40° | 1 | 1,000 times what is in the oil |
| 60° | 1 | 300 times what is in the oil |

the paper, and the purpose of the paper is to keep out moisture and oxygen. For service-aged transformers rated less than 69 kV, results of up to 35 ppm are considered acceptable. For 69 kV through 288 kV, the DGA test result of 25 ppm is considered acceptable. For greater than 288 kV, moisture should not exceed 20 ppm. However, the use of absolute values for water does not always guarantee safe conditions, and the percent by dry weight should be determined. See table 12, "Doble Limits for In-Service Oils," in section 4.6.5. If values are higher, the oil should be processed. If the transformer is kept as dry and free of oxygen as possible, transformer life will be extended.

Reclamation specifies that manufacturers dry new transformers to no more than 0.5% M/DW during commissioning. In a transformer having 10,000 pounds of paper insulation, this means that 10,000 x 0.005 = 50 pounds of water (about 6 gallons) is in the paper. This is not enough moisture to be detrimental to electrical integrity. When the transformer is new, this water is distributed equally through the transformer. It is extremely important to remove as much water as possible.

When the transformer is energized, water begins to migrate to the coolest part of the transformer and the site of the greatest electrical stress. This location is normally the insulation in the lower one-third of the winding [5]. Paper insulation has a much greater affinity for water than does the oil. The water will distribute itself unequally, with much more water being in the paper than in the oil. The paper will partially dry the oil by absorbing water out of the oil. Temperature is also a big factor in how the water distributes itself between the oil and paper. See table 11 above for comparison.

The table above shows the tremendous attraction that paper insulation has for water. The ppm of water in oil shown in the DGA is only a small part of the water in the transformer. It is important that, when an oil sample is taken, you record the oil temperature from the top oil temperature gage.

Some laboratories give percent M/DW of the insulation in the DGA. Others give percent oil saturation, and some give only the ppm of water in the oil. If you have an accurate temperature of the oil and the ppm of water, the Nomograph (figure 23, section 4.5.2) will give percent M/DW of the insulation and the percent oil saturation.

Where does the water come from? Moisture can be in the insulation when it is delivered from the factory. If the transformer is opened for inspection, the insulation can absorb moisture from the atmosphere. If there is a leak, moisture can enter in the form of water or humidity in air. Moisture is also formed by the degradation of insulation as the transformer ages. Most water penetration is flow of wet air or rain water through poor gasket seals due to pressure difference caused by transformer cooling. During rain or snow, if a transformer is removed from service, some transformer designs cool rapidly and the pressure inside drops. The most common moisture ingress points are gaskets between bushing bottoms and the transformer top and the pressure relief device gasket. Small oil leaks, especially in the oil cooling piping, will also allow moisture ingress. With rapid cooling and the resultant pressure drop, relatively large amounts of water and water vapor can be pumped into the transformer in a short time. It is important to repair small oil leaks; the small amount of visible oil is not important in itself, but it also indicates a point where moisture will enter [22].

It is critical for life extension to keep transformers as dry and as free of oxygen as possible. Moisture and oxygen cause the paper insulation to decay much faster than normal and form acids, sludge, and more moisture. Sludge settles on windings and inside the structure, causing transformer cooling to be less efficient, and slowly over time temperature rises. (This was discussed earlier in "3. Transformer Cooling Methods.") Acids cause an increase in the rate of decay, which forms more acid, sludge, and moisture at a faster rate [20]. This is a vicious cycle of increasing speed forming more acid and causing more decay. The answer is to keep the transformer as dry as possible and as free of oxygen as possible. In addition, oxygen inhibitor should be watched in the DGA testing. The transformer oil should be dried when moisture reaches the values according to table 12. Inhibitor should be added (0.3% by weight ASTM D-3787) when the oil is processed.

**Water can exist in a transformer in five forms.**

1. Free water, at the bottom of the tank.
2. Ice at the tank bottom (if the oil specific gravity is greater than 0.9, ice can float).
3. Water can be in the form of a water/oil emulsion.
4. Water can be dissolved in the oil and is given in ppm in the DGA.
5. Water can be in the form of humidity if transformers have an inert gas blanket.

Free water causes few problems with dielectric strength of oil; however, it should be drained as soon as possible. Having a water-oil interface allows oil to dissolve water and transport it to the insulation. Problems with moisture in insulation were discussed above. If the transformer is out of service in winter, water can freeze. If oil specific gravity is greater than 0.9 (ice specific gravity), ice will float. This can cause transformer failure if the transformer is energized with floating ice inside. This is one reason that DGA laboratories test specific gravity of transformer oil.

The amount of moisture that can be dissolved in oil increases with temperature. (See figure 19.) This is why hot oil is used to dryout a transformer. A water/oil emulsion can be formed by purifying oil at too high temperature. When the oil cools, dissolved moisture forms an emulsion [20]. A water/oil emulsion causes drastic reduction in dielectric strength.

How much moisture in insulation is too much? When the insulation gets to 2.5% M/DW or 30% oil saturation (given on some DGAs), the transformer should have a dry out with vacuum if the tank is rated for vacuum. If the transformer is old, pulling a vacuum can do more harm than good. In this case, it is better to do round-the-clock recirculation with a Bowser drying the oil as much as possible, which will pull water out of the paper. At 2.5% M/DW, the paper insulation is degrading much faster than normal [5]. As the paper is degraded, more water is produced from the decay products, and the transformer becomes even wetter and decays even faster. When a transformer gets above 4% M/DW, it is in danger of flashover if the temperature rises to 90°C.

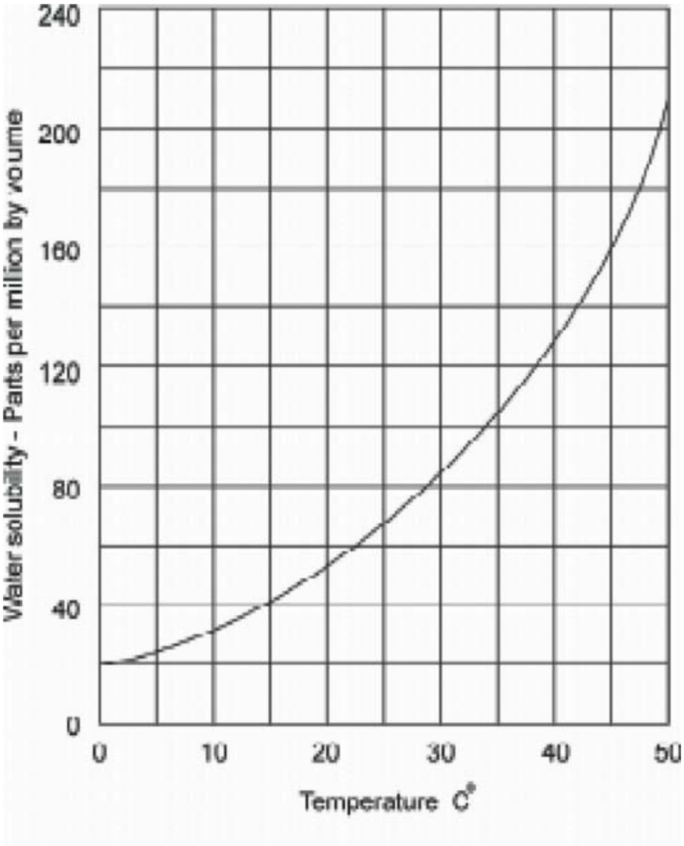


Figure 19.—Maximum Amount of Water Dissolved in Mineral Oil Versus Temperature.

**4.5.1 Dissolved Moisture in Transformer Oil.** Moisture is given in the dissolved gas analysis in ppm, and some laboratories also give percent saturation. Percent saturation means percent saturation of water in the oil. This is a percentage of how much water is in the oil compared with the maximum amount of water the oil can hold. In figure 19, it can be seen that the amount of water the oil can dissolve is greatly dependent on temperature. The curves (figure 20) below are percent saturation curves. On the left line, find the ppm of water from your DGA. From this point, draw a horizontal with a straight edge. From the oil temperature, draw a vertical line. At the point where the lines intersect, read the percent saturation curve. If the point falls between two saturation curves, estimate the percent saturation based on where the point is located. For example, if the water is 30 ppm and the temperature is 40 °C, you can see on the curves that this point of intersection falls about halfway between the 20% curve and the 30% curve. This means that the oil is approximately 25% saturated. Curves shown on figure 20 are from IEEE 62-1995 [19].

Caution: Below 30 °C, the curves are not very accurate.

**4.5.2 Moisture in Transformer Insulation.** The illustration (figure 21) shows how moisture is distributed throughout transformer insulation. Notice that the moisture is distributed according to temperature, with most moisture at the bottom and less as temperature increases toward the top. In this example, there is almost twice the moisture near bottom as there is at the top. Most service-aged transformers fail in the lower one-third of the windings, which is the area of most moisture. It is also the area of most electrical stress.

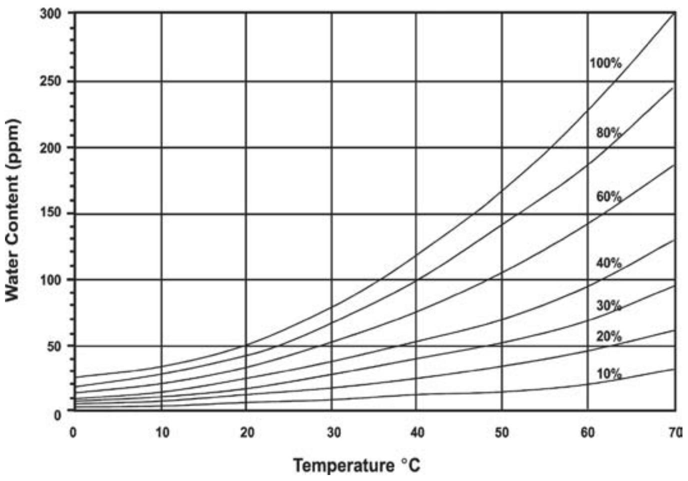


Figure 20.—Transformer Oil Percent Saturation Curves.

Moisture and oxygen are two of the transformer's worst enemies. It is very important to keep the insulation and oil as dry as possible and as free of oxygen as possible.

Failures due to moisture are the most common cause of transformer failures [5]. Without an accurate oil temperature, it is impossible for laboratories to provide accurate information about the M/DW or percent saturation. It will also be impossible for you to calculate this information accurately.

Experts disagree on how to tell how much moisture is in the insulation based on how much moisture is in the oil (ppm). At best, methods to determine moisture in the insulation based solely on DGA are inaccurate. The methods discussed below to determine moisture in the insulation are approximations and no decision should be made based on one DGA. However, keep in mind that the life of the transformer is the life of the insulation. The insulation is quickly degraded by excess moisture and the presence of oxygen. Base any decisions on several DGAs over a period of time and establish a trend of increasing moisture.

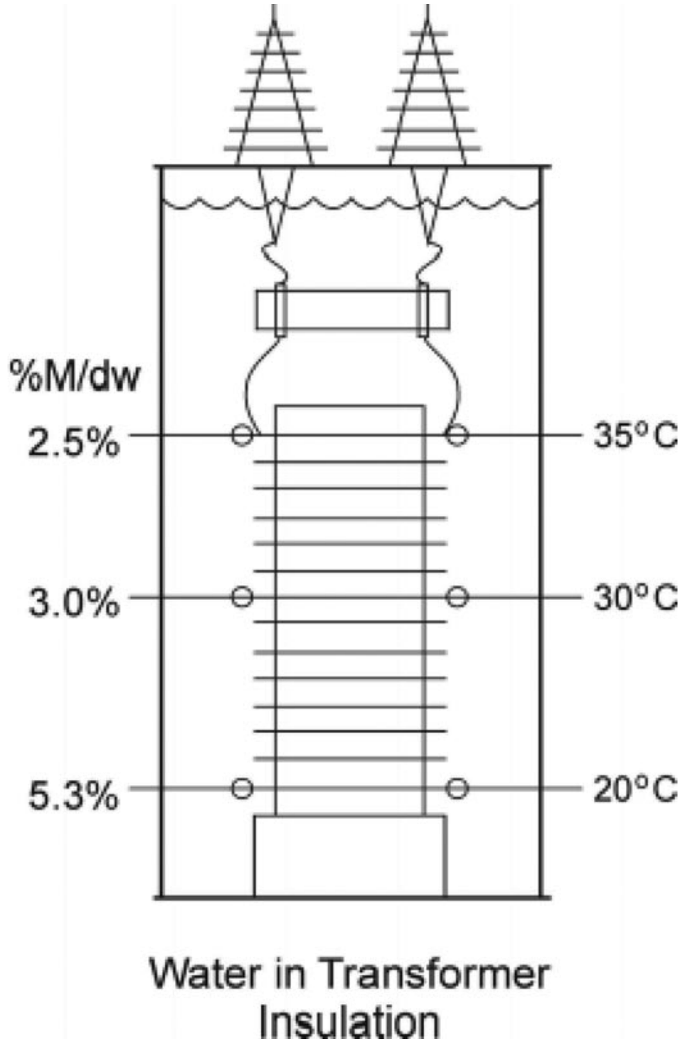


Figure 21.—Water Distribution in Transformer Insulation.

If the lab does not provide the percent M/DW, IEEE 62-1995 [19] gives a method. From the curve (figure 22), find temperature of the bottom oil sample and add 5°C. Do not use the top oil temperature. This approximates temperature of the bottom third (coolest part) of the winding, where most of the water is located. From this temperature, move up vertically to the curve. From this point on the curve, move horizontally to the left and find the Myers Multiplier number. Take this number and multiply the ppm of water shown on the DGA. The result is percent M/DW in the upper part of the insulation. This method gives less amount of water than the General Electric nomograph.

This nomograph, published by General Electric in 1974 (figure 23), gives the percent saturation of oil and percent M/DW of insulation. Use the nomograph to check yourself after you have completed the method illustrated in figure 22. The nomograph in figure 23 will show more moisture than the IEEE method.

The curves in figure 23 are useful to help understand relationships between temperature, percent saturation of the oil, and percent M/DW of the insulation. For example, pick a point on the ppm water line, say 10 ppm. Place a straight edge on that point and pick a point on the temperature line, say 45°C. Read the percent saturation and percent M/DW on the center lines. In this example, percent saturation is about 6.5% and the

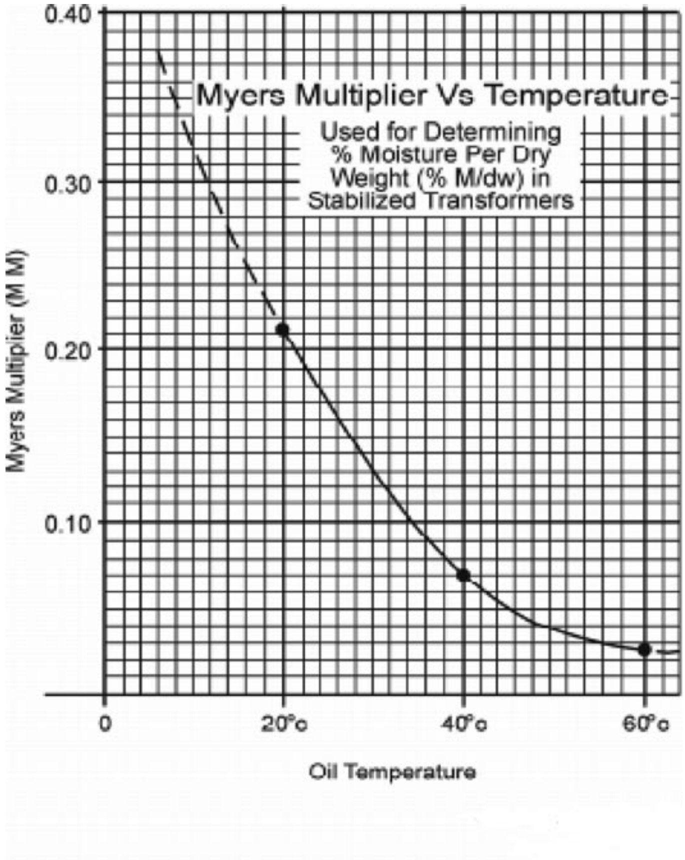


Figure 22.—Myers Multiplier Versus Temperature.

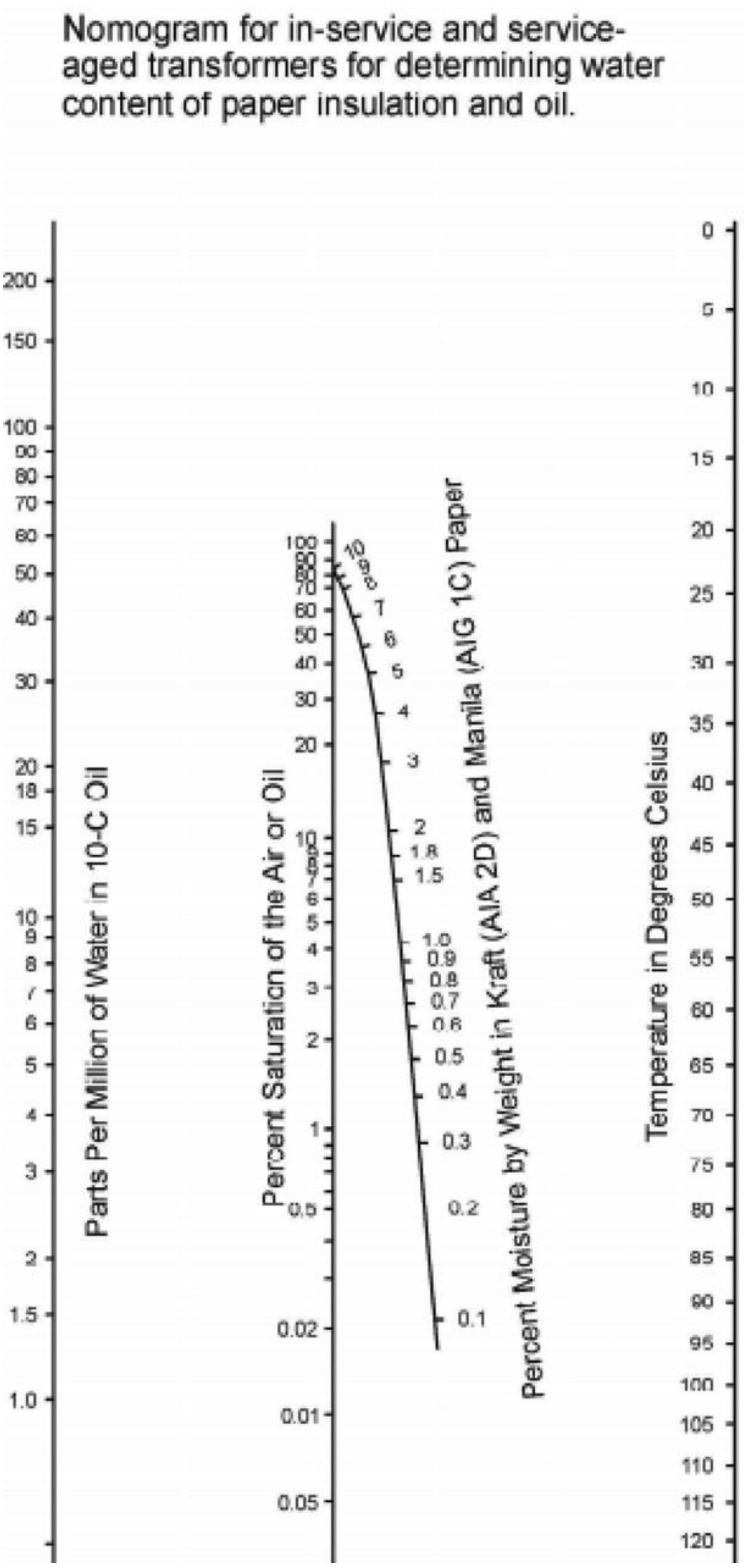


Figure 23.—Water Content of Paper and Oil Nonogram.

% M/DW is about 1.5%. Now, hold the 10 ppm point and move the sample temperature upward (cooler), and notice how quickly the moisture numbers increase. For example, use 20° C and read the % saturation of oil at about 18.5% and the % M/DW at about 3.75%. The cooler the oil, the higher the moisture percentage for the same ppm of water in the oil.

Do not make a decision on dryout based on only one DGA and one calculation; it should be based on trends over a period of time. Take additional samples and send them for analysis. Take extra care to make sure the oil temperature is correct. You can see by the nomograph that moisture content varies dramatically with temperature. Take extra care that the sample is not exposed to air. If after using the more conservative IEEE method and again subsequent samples show M/DW is 2.5% or more and the oil is 30% saturated or more, the transformer should be dried as soon as possible. Check the nomograph and curves above to determine the percent saturation of the oil.The insulation is degrading much faster than normal due to the high moisture content. Drying can be an expensive process; it is prudent to consult with others before making a final decision to do dryout. However, it is much less expensive to perform a dryout than to allow a transformer to degrade faster than normal, substantially shortening transformer life.

## 4.6 Transformer Oil Tests That Should Be Done Annually With the Dissolved Gas Analysis.

**4.6.1 Dielectric Strength.** This test measures the voltage at which the oil electrically breaks down. The test gives a good indication of the amount of contaminants (water and oxidation particles) in the oil. DGA laboratories typically use ASTM Test Method No. D-877 or D-1816. The acceptable minium breakdown voltage is 30 kV for transformers 287.5 kV and above, and 25 kV for high voltage transformers rated under 287.5 kV. If the dielectric strength test falls below these numbers, the oil should be reclaimed. Do not base any decision on one test result, or on one type of test; instead, look at all the information over several DGAs and establish trends before making any decision.

The dielectric strength test is not extremely valuable; moisture in combination with oxygen and heat will destroy cellulose insulation long before the dielectric strength of the oil has given a clue that anything is going wrong [5]. The dielectric strength test also reveals nothing about acids and sludge. The tests explained below are much more important.

**4.6.2 Interfacial Tension (IFT).** This test (ASTM D-791-91) [21], is used by DGA laboratories to determine the interfacial tension between the oil sample

]

and distilled water. The oil sample is put into a beaker of distilled water at a temperature of 25°C. The oil should float because its specific gravity is less than that of water, which is one. There should be a distinct line between the two liquids. The IFT number is the amount of force (dynes) required to pull a small wire ring upward a distance of 1 centimeter through the water/oil interface. (A dyne is a very small unit of force equal to 0.000002247 pound.) Good clean oil will make a very distinct line on top of the water and give an IFT number of 40 to 50 dynes per centimeter of travel of the wire ring.

As the oil ages, it is contaminated by tiny particles (oxidation products) of the oil and paper insulation. These particles extend across the water/oil interface line and weaken the tension between the two liquids. The more particles, the weaker the interfacial tension and the lower the IFT number. The IFT and acid numbers together are an excellent indication of when the oil needs to be reclaimed. It is recommended the oil be reclaimed when the IFT number falls to 25 dynes per centimeter. At this level, the oil is very contaminated and must be reclaimed to prevent sludging, which begins around 22 dynes per centimeter. See FIST 3-5 [20].

If oil is not reclaimed, sludge will settle on windings, insulation, etc., and cause loading and cooling problems discussed in an earlier section. This will greatly shorten transformer life.

There is a definite relationship between the acid number, the IFT, and the number of years in service. The accompanying curve (figure 24) shows the relationship and is found in many publications. (It was originally published in the AIEE transactions in 1955.) Notice that the curve shows the normal service limits both for the IFT and the acid number.

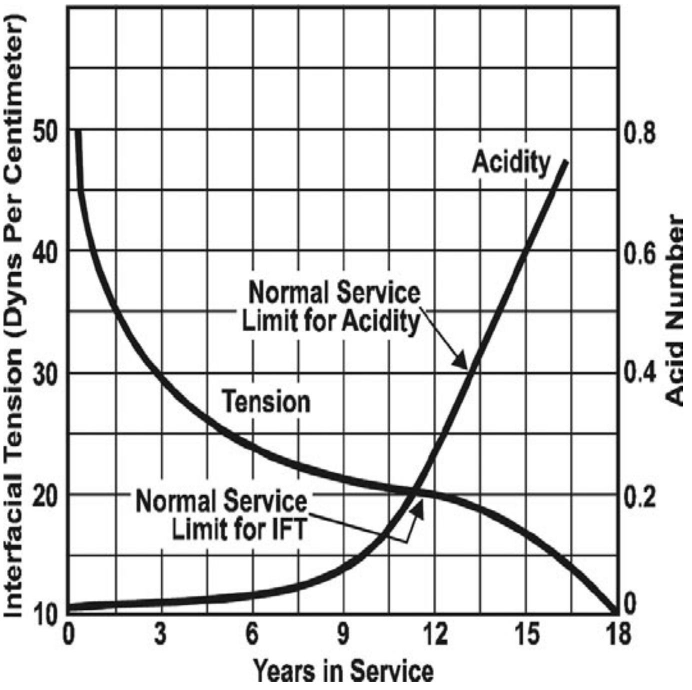


Figure 24.—Interfacial Tension, Acid Number Years in Service.

**4.6.3 Acid Number.** Acid number (acidity) is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 gram (gm) of transformer oil. The higher the acid number, the more acid is in the oil. New transformer oils contain practically no acid. Oxidation of the insulation and oils forms acids as the transformer ages. The oxidation products form sludge and precipitate out inside the transformer. The acids attack metals inside the tank and form soaps (more sludge). Acid also attacks cellulose and accelerates insulation degradation. Sludging has been found to begin when the acid number reaches 0.40; it is obvious that the oil should be reclaimed before it reaches 0.40. It is recommended that the oil be reclaimed when it reaches 0.20 mg KOH/gm [20]. As with all others, this decision must not be based on one DGA test, but watch for rising trend in the acid number each year. Plan ahead and begin budget planning before the acid number reaches 0.20.

**4.6.4 Test for Oxygen Inhibitor Every 3 to 5 Years with the Annual DGA Test.** In previous sections, the need to keep the transformer dry and O 2 free was emphasized. Moisture is destructive to cellulose and even more so in the presence of oxygen. Some publications state that each time you double the moisture (ppm), you halve the life of the transformer. As was discussed, acids are formed that attack the insulation and metals which form more acids, causing a viscous cycle. Oxygen inhibitor is a key to extending the life of transformers. The inhibitor currently used is Ditertiary Butyl Paracresol (DBPC). This works sort of like a sacrificial anode in grounding circuits. The oxygen attacks the inhibitor instead of the cellulose insulation. As this occurs and the transformer ages, the inhibitor is used up and needs to be replaced. The ideal amount of DBPC is 0.3% by total weight of the oil (ASTM D-3487).

Have the inhibitor content tested with the DGA every 3 to 5 years. If the inhibitor is 0.08% the transformer is considered uninhibited, and the oxygen freely attacks the cellulose. If the inhibitor falls to 0.1%, the transformer should be re-inhibited. For example, if your transformer tested 0.1%, you need to go to 0.3% by adding 0.2% of the total weight of the transformer oil. The nameplate gives the weight of oil—say 5,000 pounds—so 5,000 pounds X 0.002 = 10 pounds of DBPC needs to be added. It's ok if you get a little too much DBPC; this does not hurt the oil. Dissolve 10 pounds of DBPC in transformer oil that you have heated to the same temperature as the oil inside the transformer. It may take some experimentation to get the right amount of oil to dissolve the DBPC. Mix the oil and inhibitor in a clean container until all the DBPC is dissolved. Add this mixture to the transformer using the method given in the transformer instruction manual for adding oil.

Caution: Do not attempt this unless you have had experience. Contact an experienced contractor or experienced Reclamation people if you need help.

In either case, do not neglect this important maintenance function; it is critical to transformer insulation to have the proper amount of oxygen inhibitor.

**4.6.5 Power Factor.** Power factor indicates the dielectric loss (leakage current) of the oil. This test may be done by the DGA laboratories. It may also be done by Doble testing. A high power factor indicates deterioration and/or contamination by-products such as water, carbon, or other conducting particles; metal soaps caused by acids (formed as mentioned above); attacking transformer metals; and products of oxidation. The DGA labs normally test the power factor at 25°C and 100°C. Doble information [23] indicates the in-service limit for power factor is less than 0.5% at 25 °C. If the power factor is greater than 0.5% and less than 1.0%, further investigation is required; the oil may require replacement or fullers earth filtering. If the power factor is greater than 1.0% at 25°C, the oil may cause failure of the transformer; replacement or reclaiming is required. Above 2%, the oil should be removed from service and reclaimed or replaced because equipment failure is a high probability.

**4.6.6 Furans.** Furans are a family of organic compounds which are formed by degradation of paper insulation (ASTM D-5837). Overheating, oxidation, and degradation by high moisture content contribute to the destruction of insulation and form furanic compounds. Changes in furans between DGA tests are more important than individual numbers. The same is true for dissolved gases. Transformers with greater than 250 parts per billion (ppb) should be investigated because paper insulation is being degraded. Also look at the IFT and acid number.
Doble in-service limits are reproduced below to support the above recommended guidelines.

Table 12 below is excerpted from Doble Engineering Company's Reference Book on Insulating Liquids and Gases [23]. These Doble Oil Limit tables support information given in prior sections in this FIST manual and are shown here as summary tables.

**Table 12.—Doble Limits for In-Service Oils**

| | Voltage Class | | |
|---|---|---|---|
| | ≤ 69 kV | >69 ≤ 288 kV | >288 kV |
| Dielectric Breakdown Voltage, D 877, kV min | 26 | 30 | [1] |
| Dielectric Breakdown Voltage D 1816, .04-inch gap, kV, min. | 20 | 20 | 25 |
| Power Factor at 25 °C, D 924, max. | 0.5 | 0.5 | 0.5 |
| Water Content, D 1533, ppm, max. | [2]35 | [2]25 | [2]20 |
| Interfacial Tension, D 971, dynes/cm, min. | 25 | 25 | 25 |
| Neutralization Number, D 974, mg KOH/gm, max. | 0.2 | 0.15 | 0.15 |
| Visual Exam | clear and bright | clear and bright | clear |
| Soluble Sludge | [3]ND | [3]ND | [3]ND |

[1] D 877 test is not as sensitive to dissolved water as the D 1816 test and should not be used with oils for extra high voltage (EHV) equipment. Dielectric breakdown tests do not replace specific tests for water content.

[2] The use of absolute values of water-in-oil (ppm) do not always guarantee safe conditions in electrical apparatus. The percent by dry weight should be determined from the curves provided. See the information in section. "4.5 Moisture Problems."

[3] ND = None detectable.

These recommended limits for in-service oils are not **intended to be used as absolute requirements** for removing oil from service but to provide guidelines to aid in determining when remedial action is most beneficial. Remedial action will vary depending upon the test results. Reconditioning of oil, that is, particulate removal (filtration) and drying, may be required if the dielectric breakdown voltage or water content do not meet these limits. Reclamation (clay filtration) or replacement of the oil may be required if test values for power factor, interfacial tension, neutralization number, or soluble sludge do not meet recommended limits.

Additional guidelines given in table 13 have been found useful.

Table 13.—Additional Guidelines for In-Service Oils

| Power factor at 25 °C | |
|---|---|
| ≤ 0.5% | Acceptable |
| > 0.5 ≤ 1.0% | Investigate, oil may require replacement or clay treatment |
| > 1.0 ≤ 2.0% | Investigate, oil may cause failure of the equipment, oil may require replacement or clay treatment |
| > 2.0% | Remove from service, investigate, oil may require replacement or clay treatment |

| Neut. No. (mg KOH/gm) | IFT (dynes/cm) | |
|---|---|---|
| < 0.05 | ≥25 | Acceptable |
| ≥ 0.05 < 0.15 | ≥ 22 < 25 | Clay treat or replace at convenience ≥ 345 kV, clay treat or replace in immediate future |
| ≥0.15 < 0.5 | ≥16 > 22 | Clay treat or replace in immediate future |
| ≥0.5 | <16 | Replace[1] |

[1] When an oil is allowed to sludge in service, special treatment may be required to clean the core, coil, and tank.

### *Oil Treatment Specifications.*

After the oil is treated, the results should be as follows.

| **Gases** | | **Physical Properties** | |
|---|---|---|---|
| $H_2$ | 5 ppm or less | Water | less than 10 ppm |
| $CH_4$ | 5 ppm or less | Dielectric strength | 38 kV min. ASTM D-1816 |
| $C_2H_2$ | 0 ppm | IFT | 36 dynes/cm min. |
| CO | 20 ppm or less | Acid number | 0.3 mg KOH/gm max. |
| $CO_2$ | 300 ppm or less | $O_2$ inhibitor | 0.3% by oil weight min. |
| $O_2$ | 4,000 ppm or less | | |

4.6.7 Taking Oil Samples for DGA. Sampling procedures and lab handling are usually areas that cause the most problems in getting an accurate DGA. There are times when atmospheric gases, moisture, or hydrogen take a sudden leap from one DGA to the next. As has been mentioned, at these times, one should immediately take another sample to confirm DGA values. It is, of course, possible that the transformer has developed an atmospheric leak, or that a fault has suddenly occurred inside. More often, the sample has not been taken properly, or it has been contaminated with atmospheric gases or mishandled in other ways. The sample must be protected from all contamination, including atmospheric exposure.

Do not take samples from the small sample ports located on the side of the large sample (drain) valves. These ports are too small to adequately flush the large valve and pipe nipple connected to the tank; in addition, air can be drawn past the threads and contaminate the sample. Fluid in the valve and pipe nipple remain dormant during operation and can be contaminated with moisture, microscopic stem packing particles, and other particles. The volume of oil in this location can also be contaminated with gases, especially hydrogen. Hydrogen is one of the easiest gasses to form. With hot sun on the side of the transformer tank where the sample valve is located, high ambient temperature, high oil temperature, and captured oil in the sample valve and extension, hydrogen formed will stay in this area until a sample is drawn.

The large sample (drain) valve can also be contaminated with hydrogen by galvanic action of dissimilar metals. Sample valves are usually brass, and a brass pipe plug should be installed when the valve is not being used. If a galvanized or black iron pipe is installed in a brass valve, the dissimilar metals produce a thermocouple effect, and circulating currents are produced. As a result, hydrogen is generated in the void between the plug and valve gate. If the valve is not flushed very thoroughly the DGA will show high hydrogen.

Oil should not be sampled for DGA purposes when the transformer is at or below freezing temperature. Test values which are affected by water (such as dielectric strength, power factor, and dissolved moisture content) will be inaccurate.

Caution: Transformers must not be sampled if there is a negative pressure (vacuum) at the sample valve.

This is typically not a problem with conservator transformers. If the transformer is nitrogen blanketed, look at the pressure/vacuum gage. If the pressure is positive, go ahead and take the sample. If the pressure is negative, a vacuum exists at the top of the transformer. If there is a vacuum at the bottom, air will be pulled in when the sample valve is opened. Wait until the pressure gage reads positive before sampling. Pulling in a volume of air could be disastrous if the transformer is energized.

If negative pressure (vacuum) is not too high, the weight of oil (head) will make positive pressure at the sample valve, and it will be safe to take a sample. Oil head is about 2.9 feet (2 feet 10.8 inches) of oil per pounds per square inch (psi). If it is important to take the sample even with a vacuum showing at the top, proceed as described below.

Use the sample tubing and adaptors described below to adapt the large sample valve to •-inch tygon tubing. Fill a length (2 to 3 feet) of tygon tubing with new transformer oil (no air bubbles) and attach one end to the pipe plug and the other end to the small valve. Open the large sample (drain) valve a small amount and very slowly crack open the small valve. If oil in the tygon tubing moves toward the transformer, shut off the valves immediately. Do not allow air to be pulled into the transformer. If oil moves toward the transformer, there is a vacuum at the sample valve. Wait until the pressure is positive before taking the DGA sample. If oil is pushed out of the tygon tubing into the waste container, there is a positive pressure and it is safe to proceed with DGA sampling. Shut off the valves and configure the tubing and valves to take the sample per the instructions below.

**DGA Oil Sample Container.** Glass sample syringes are recommended. There are different containers such as stainless steel vacuum bottles and others. It is recommended that only glass syringes be used. If there is a small leak in the sampling tubing or connections, vacuum bottles will draw air into the sample, which cannot be seen inside the bottle. The sample will show high atmospheric gases and high moisture if the air is humid. Other contaminates such as suspended solids or free water cannot be seen inside the vacuum bottle. Glass syringes are the simplest to use because air bubbles are easily seen and expelled. Other contaminates are easily seen, and another sample can be immediately taken if the sample is contaminated. The downside is that glass syringes must be handled carefully and must be protected from direct sunlight. They should be returned to their shipping container immediately after taking a sample. If they are exposed to sunlight for any time, hydrogen will be generated and the DGA will show false hydrogen readings.

For these reasons, glass syringes are recommended, and the instructions below include only this sampling method.

Obtain a brass pipe plug (normally 2 inches) that will thread into the sample valve at the bottom of the transformer. Drill and tap the pipe plug for 1/8-inch NPT and insert a 1/8-inch pipe nipple (brass if possible) and attach a small 1/8-inch valve for controlling the sample flow. Attach a 1/8-inch tygon tubing adaptor to the small valve outlet. Sizes of the piping and threads above do not matter; any arrangement with a small sample valve and adaptor to 1/8-inch tygon tubing will suffice. See figure 25.

**Taking the Sample.**

- Remove the existing pipe plug and inspect the valve opening for rust and debris.
- Crack open the valve and allow just enough oil to flow into the waste container to flush the valve and threads. Close the valve and wipe the threads and outlet with a clean dry cloth.

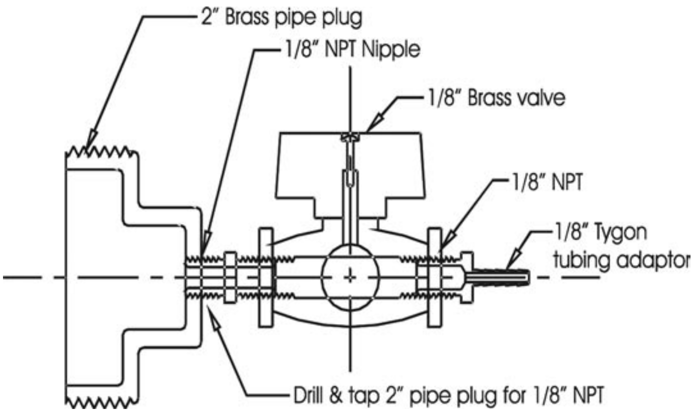

2" Brass pipe plug
1/8" NPT Nipple
1/8" Brass valve
1/8" NPT
1/8" Tygon tubing adaptor
Drill & tap 2" pipe plug for 1/8" NPT

Figure 25.—Oil Sampling Piping.

- Re-open the valve slightly and flush approximately 1 quart into the waste container.
- Install the brass pipe plug (described above) and associated 1/8-inch pipe and small valve, and a short piece of new 1/8-inch tygon tubing to the outlet of the 1/8-inch valve.
- Never use the same sample tubing on different transformers. This is one way a sample can be contaminated and give false readings.
- Open both the large valve and small sample valve and allow another quart to flush through the sampling apparatus. Close both valves. Do this before attaching the glass sample syringe. Make sure the short piece of tygon tubing that will attach to the sample syringe is installed on the 1/8-inch valve before you do this.
- Install the glass sample syringe on the short piece of •-inch tubing. Turn the stopcock handle on the syringe so that the handle points toward the syringe. Note: The handle always points toward the closed port. The other two ports are open to each other. See figure 26.

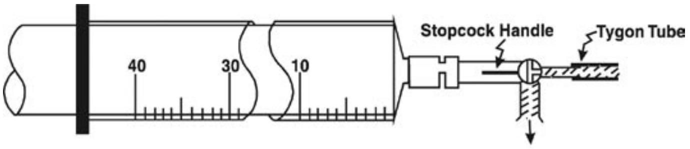


Figure 26.—Sample Syringe (Flushing).

- Open the large sample valve a small amount and adjust the 1/8-inch valve so that a gentle flow goes through the flushing port of the glass syringe into the waste bucket.
- Slowly turn the syringe stopcock handle so that the handle points to the flushing port (figure 27). This closes the flushing and allows oil to flow into the sample syringe. Do not pull the syringe handle; this will create a vacuum and allow bubbles to form. The syringe handle (piston) should back out very slowly. If it moves too fast, adjust the small 1/8-inch valve until the syringe slows, and hold your hand on the back of the piston so you can control the travel.

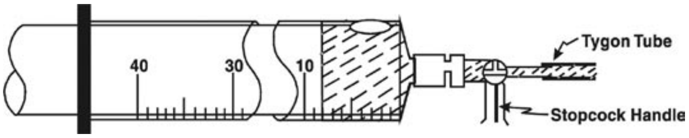


Figure 27.—Sample Syringe (Filling).

- Allow a small amount, about 10 cubic centimeters (cc), to flow into the syringe and turn the stopcock handle again so that it points to the syringe. This will again allow oil to come out of the flushing port into the waste bucket.
- Pull the syringe off the tubing, but do not shut off the oil flow. Allow the oil flow to continue into the waste bucket.
- Hold the syringe vertical and turn the stopcock up so that the handle points away from the syringe. Press the syringe piston to eject any air bubbles, but leave 1 or 2 cc oil in the syringe. See the accompanying figure 28.

Caution: Do not eject all the oil, or air will reenter.

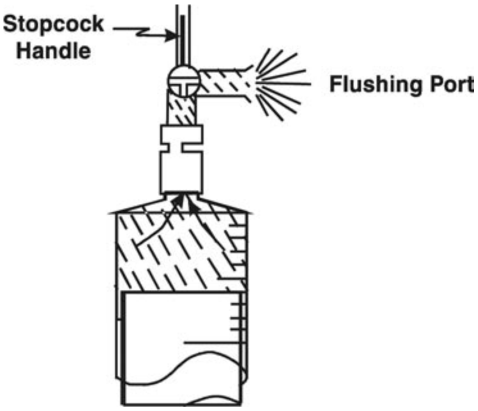


Figure 28.—Sample Syringe Bubble Removal.

- Turn the stopcock handle toward the syringe. The small amount of oil in the syringe should be free of bubbles and ready to receive the sample. If there are still bubbles at the top, repeat the process until you have a small amount of oil in the syringe with no bubbles.
- Reattach the tygon tubing. This will again allow oil to flow out of the flushing port. Slowly turn the stopcock handle toward the flushing port which again will allow oil to fill the syringe. The syringe piston will again back slowly out of the syringe. Allow the syringe to fill about 80% full. Hold the piston so you can stop its movement at about 80% filled.

Caution: Do not pull the piston. This will cause bubbles to form.

- Close the stopcock by turning the handle toward the syringe. Oil again will flow into the waste container. Shut off both valves, remove the sampling apparatus, and reinstall the original pipe plug.

Caution: Do not eject any bubbles that form after the sample is collected; these are gases that should be included in the lab sample.

- Return the syringe to its original container immediately.

Do not allow sunlight to impact the container for any length of time. Hydrogen will form and give false readings in the DGA.

- Carefully package the syringe in the same manner that it was shipped to the facility and send it to the lab for processing.
- Dispose of waste oil in the plant waste oil container.

**4.6.8 Silicone Oil-Filled Transformers.** Silicone oils became more common when PCBs were discontinued. They are mainly used in transformers inside buildings and that are smaller than generator step-up transformers. Silicone oils have a higher fire point than mineral oils and, therefore, are used where fire concerns are more critical. Information below is taken from the IEEE publication, from Doble, from articles, from IEC 60599 concepts, and from Delta X Research's/Transformer Oil Analyst rules. Silicone oil dissolved gas analysis is in the beginning stages, and the suggested methods and limits below are subject to change as we gain more experience. However, in the absence of any other methods and limits, use the ones below as a beginning.

Silicone oils used in transformers are polydimethylsiloxane fluids, which are different than mineral oils. Many of the gases generated by thermal and electrical faults are the same. The gases are generated in different proportions than with transformer mineral oils. Also, some fault gases have different solubilities in silicone oils than in mineral oils. Therefore, the same faults would produce different concentrations and different generation rates in silicone oils than mineral oils.

As with mineral oil-filled transformers, three principal causes of gas generation are aging, thermal faults, and/or electrical faults resulting in deterioration of solid insulation and deterioration of silicone fluid. These faults have been discussed at length in prior sections and will not be discussed in great detail here.

Overheating of silicone oils causes degradation of fluid and generation of gases. Gases generated depend on the amount of dissolved oxygen in the fluid, temperature, and how close bare copper conductors are to the heating. When a transformer is new, silicone oil will typically contain a lot of oxygen. Silicone transformers are typically sealed and pressurized with nitrogen. New silicone oil is not degassed; and, as a rule, oxygen concentration will be equivalent to oxygen solubility (maximum) in silicone. The silicone has been exposed to atmosphere for some time during manufacture of the transformer and manufacturer and storage of silicone oil itself. Therefore, carbon monoxide and carbon dioxide are easily formed and dissolved in the silicone due to the abundance of oxygen in the oil resulting from this atmospheric exposure. In normal new silicone transformers (no faults), both carbon monoxide and carbon dioxide will be generated in the initial years of operation. As the transformer ages and oxygen is depleted, generation of these gases slows and concentrations level off [25]. See figure 29 for the relationship of decreasing oxygen and increasing carbon monoxide and carbon dioxide as a transformer ages. This curve is for general information only and should not be taken to represent any particular transformer. A real transformer with changes in loading, ambient temperatures, and various duty cycles would make these curves look totally different.

After the transformer is older (assuming no faults have occurred), oxygen concentration will reach equilibrium (figure 29). Reaching equilibrium may take a few years depending on the size of the transformer, loading, ambient temperatures, etc. After this time, oxygen, carbon monoxide, and carbon dioxide level off and the rate of production of these gases from normal aging should be relatively constant. If generation rates of these gases change greatly (seen from the DGA), a fault has occurred, either thermal or electrical. Rate of generation of these gases and amounts can be used to roughly determine what the fault is. Once you notice an significant increase in rate of generation of any gas, it is a good idea to subtract the amount of gas that was already in the transformer before this increase. This ensures that gases used in the diagnosis are only gases that were generated after the fault began.

Carbon monoxide will be a lot higher in a silicone transformer than a mineral oil-filled one. The difficulty is in trying to determine what is producing the CO; is it coming from normal aging of oil or from deterioration of paper from a fault condition. The only solution is a furan analysis. If the CO content is greater than the IEEE limit of 3,000 ppm [26], and the generation rate G1 is met or exceeded, a furan analysis is recommended with the annual DGA. If a thermal fault is occurring and is producing CO and small amounts of methane and hydrogen, the fault may be masked by the normal production of CO from the silicone oil itself. If the CO generation rate has greatly increased, along with other gases, it becomes obvious that a fault has occurred. The furan analysis can only tell you if the paper is involved (being heated) in the fault.

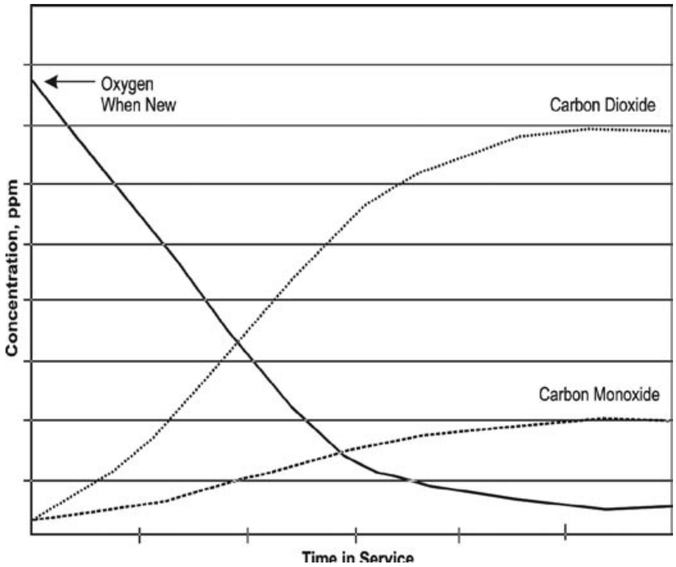


Figure 29.—Relationship of Oxygen to Carbon Dioxide and Carbon Monoxide as Transformer Ages.

Some general conclusions can be drawn by comparing silicone oil and mineral oil transformers.

1. All silicone oil filled transformers will have a great deal more CO than normal mineral oil filled transformers. CO can come from two sources, the oil itself and from degradation of paper insulation. If the DGA shows little other fault in gas generation besides CO, the only way to tell for certain if CO is coming from paper degradation (a fault) is to run a furan analysis with the DGA. If other fault gases are also being generated in significant amounts, in addition to CO, obviously there is a fault, and CO is coming from paper degradation.

2. There will generally be more hydrogen present than in a mineral oil-filled transformer.

3. Due to "fault masking," mentioned above, it is almost impossible to diagnose what is going on inside a silicone filled transformer based solely on DGA. One exception is if acetylene is being generated, there is an active arc. You must also look at gas generation rates and operating history. Look at loading history, through faults, and other incidents. It is imperative that detailed records of silicone oil filled transformers be carefully kept up-to-date. These are invaluable when a problem is encountered.

4. If acetylene is being generated in any amount, there is a definitely an active electrical arc. The transformer should be removed from service.

5. In general, oxygen in a silicone-filled transformer comes from atmospheric leaks or was present in the transformer oil when it was new. This oxygen is consumed as CO and CO2 are formed from the normal heating from operation of the transformer.

Table 14.—Comparison of Gas Limits

| Gas | Doble 95% Norm | IEEE Limits |
|---|---|---|
| Hydrogen | 511 | 200 |
| Methane | 134 | 100 |
| Ethane | 26 | 30 |
| Ethylene | 17 | 30 |
| Acetylene | 0.6 | 1 |
| CO | 1,749 | 3,000 |
| $CO_2$ | 15,485 | 30,000 |
| Total Combustibles | 2,024 | 3,360 |

Table 15.—Suggested Levels of Concern (Limits)

| Gas | L1 (ppm) | L2 (ppm) | L3 (ppm) | G1 (ppm per month) | G2 (ppm per month) |
|---|---|---|---|---|---|
| Hydrogen | 200 | 240 | 400 | 20 | 100 |
| Methane | 100 | 125 | 200 | 10 | 50 |
| Ethane | 30 | 40 | 60 | 3 | 15 |
| Ethylene | 30 | 25 | 60 | 3 | 15 |
| Acetylene | 1 | 2 | 3 | 1 | 1 |
| CO | 3,000 | 3,450 | 6,000 | 300 | 1,500 |
| $CO_2$ | 30,000 | 34,200 | 60,000 | 1,500 | 15,000 |
| TDCG | 3,360 | 3,882 | 6,723 | na | na |

6. Once the transformer has matured and the oxygen has leveled off and remained relatively constant for two or more DGA samples, if you see a sudden increase in oxygen, and perhaps carbon dioxide and nitrogen, the transformer has developed a leak.

In table 14 are IEEE limits [26], compared with Doble [25] in a study of 299 operating transformers. The table of gases from the Doble study seems more realistic. They show gas level average of 95% of transformers in the study. Note, with the last four gases, limits given by the IEEE (trial use guide) run over 70% higher than the Doble 95% norms. But with the first three gases, hydrogen, methane, and ethane, the IEEE limits are well below the amount of gas found in 95% norms in the Doble study. We obviously cannot have limits that are below the amount of gas found in normal operating transformers.

Therefore, it is suggested that we use the Doble (95% norm) limits. The 95% norm limit means that 95% of the silicone oil transformers studied had gas levels below these limits. Obviously, 5% had gases higher than these limits. These are problem transformers that we should pay more attention to.

In table 15, the IEEE limits for L1 were chosen. For L2 limits, a statistical analysis was applied, and two standard deviations were added to L1 to obtain L2. For L3 limits, the L1 limits were doubled.

Gas generation rate limits G1 are 10% of L1 limits per month. G2 generation rate limits are 50% of L1 limits per month. These basic concepts were taken from IEC 60599 [12], for mineral oil transformers and applied to silicone oil transformers due to absence of any other criteria. As our experience grows in silicone DGA, these may have to be changed, but they will be used in the beginning.

Limits L1, L2, and L3 represent the concentration in individual gases in ppm. G1 and G2 represents generation rates of individual gases in ppm per month. To obtain G1 and G2 in ppm per day divide the per month numbers by 30. Except for acetylene, G1 is 10% of L1 and G2 is 50% of L1. The generation rates (G1, G2), are points where our level of concern should increase, especially when considered with the L1, L2, and L3 limits. At G2 generation rate, we should be extremely concerned and reduce the DGA sampling interval accordingly, and perhaps plan an outage, etc.

Except for acetylene, generation rate levels G1 and G2 were taken from IEC 60599 reference [12] which is used with mineral oil transformers. Any amount of ongoing acetylene generation means active arcing inside the transformer. In this case, the transformer should be removed from service. These criteria were chosen because of an absence of any other criteria. As dissolved gas analysis criteria for silicone oils becomes better known and quantified table 15 will change to reflect new information.

As with mineral oil-filled transformers, gas generation rates are much more important that the amount of gas present. Total accumulated gas depends a lot on age (an older transformer has more gas). If the rate of generation of any combustible gas shows a sudden increase in the DGA, take another oil sample immediately to confirm the gas generation rate increase. If the second DGA confirms a generation rate increase, get some outside advice. Be careful; gas generation rates increase somewhat with temperature variations caused by increased loading and summer ambient temperatures. However, higher operating temperatures are also the most likely conditions for a fault to occur. The real question is has the increased gas generation rate been caused by a fault or increased temperature from greater loading or higher ambient temperature?

If gas generation rates are fairly constant (no big increases and less than G1 limits above), what do we do if a transformer exceeds the L1 limits? We begin to pay more attention to that transformer, just as we do with a mineral oil transformer. We may shorten the DGA sampling interval, reduce loading, check transformer cooling, get some outside advice, etc. As with mineral oil transformers, age exerts a big influence in accumulated gas. We should be much more concerned if a 3-year old transformer which has exceeded the L1 limits than if a 30-year old transformer exceeds the limits. However, if G1 generation rates are exceeded in either an old or new transformer, we should step up our level of concern.

If accumulated gas exceeds the L2 limit, we may plan to have the transformer degassed. Examine the physical tests in the DGAs and compare them to the Doble/IEEE table (table 16) (Reference Book on Insulating Liquids and Gasses) [23]. The oil should be treated in whatever manner is appropriate if these limits are exceeded.

If both L1 limits and G1 limits are exceeded, we should become more concerned. Reduce sampling intervals, get outside advice, reduce loading, check transformer cooling and oil levels, etc. If G2 generation limits are exceeded, we should be extremely concerned. It will not be long before L3 limits are exceeded, and consideration must be given to removing the transformer from service, for testing, repair, or replacement.

If acetylene is being generated, the transformer should be taken out of service. However as with mineral oil transformers, a one-time nearby lightning strike or through fault can cause a "one-time" generation of acetylene. If you notice acetylene in the DGA, immediately take another sample. If the amount of acetylene is increasing, an active electrical arc is present within the transformer. It should be taken out of service.

If you have a critical silicone (or mineral oil-filled transformer), such as a single station service transformer, or excitation transformer, you should find out if a spare is available at another facility or from Western Area Power Administration or Bonneville Power. If there are no other possible spares consider beginning the budget process for getting a spare transformer.

Table 16 lists test limits for service-aged silicone filled transformer oil. If any of these limits are exceeded, it is suggested that the oil be treated in whatever manner is appropriate to return the oil to serviceable condition.

If the above limits are exceeded in the DGA, the silicone oil should be filtered, dried or treated to correct the specific

Table 16.—Doble and IEEE Physical Test Limits for Service-Aged Silicone Fluid

| Test | Acceptable Limits | Unacceptable Values Indicate | ASTM Test Method |
|---|---|---|---|
| Visual | Clear free of particles | Particulates, free water | D 1524<br>D 2129 |
| Dielectric breakdown voltage | 30 kV | Particulates, dissolved water | D 877 |
| Water content maximum | 70 ppm (Doble)<br>100 ppm (IEEE) | Dissolved water contamination | D 1533 |
| Power factor max. at 25 °C | 0.2 | Polar/ionic contamination | D 924 |
| Viscosity at 25 °C, cSt | 47.5–52.5 | Fluid degradation contamination | D 44 |
| Acid neutralization number max, mg KOH/gm | 0.1 (Doble)<br>0.2 (IEEE) | Degradation of cellulose or contamination | D 974 |

**Note:** If only one number appears, both Doble and IEEE have the same limit.

problem.

## 4.7 Transformer Testing

When the transformer is new before energizing and every 3 to 5 years, the transformer and bushings should be Doble tested. Transformer testing falls into three broad categories: Factory testing when the transformer is new or has been refurbished, acceptance testing upon delivery, and field testing for maintenance and diagnostic purposes. Some tests at the factory are common to most power transformers, but many of the factory tests are transformer- specific. Table 17 lists several tests. This test chart has been adapted from IEEE 62-1995 reference [19]. Not all of the listed tests are done at the factory, and not all of them are done in the field. Each transformer and each situation is different, requiring its own unique approach and tests.

Details of how to run specific tests will not be addressed in this FIST. It would be impractical to repeat how to do Doble testing of a transformer when the information is readily available in Doble publications. With some exceptions, this is true for most of the tests. Specific information is readily available within the test instrument manufacturers literature. Another example is the transformer turns ratio test (TTR); specific test information is available with the instrument. However, information on some tests may not be available and will be covered briefly.

**4.7.1 Winding Resistances.** Winding resistances are tested in the field to check for loose connections, broken strands, and high contact resistance in tap changers. Key gases increasing in the DGA will be ethane and/or ethylene and possibly methane. Results are compared to other phases in wye connected transformers or between pairs of terminals on a delta-connected winding to determine if a resistance is too high. Resistances can also be compared to the original factory measurements. Agreement within 5% for any of the above comparisons is considered satisfactory. You may have to convert resistance measurements to the reference temperature used at the factory (usually 75 °C) to compare your resistance measurements to the factory results. To do this use the following formula:

$$Rs = Rm\frac{Ts + Tk}{Tm + Tk}$$

Rs = Resistance at the factory reference temperature (found in the transformer manual)

Rm = Resistance you actually measured

Ts = Factory reference temperature (usually 75°C)

Tm = Temperature at which you took the measurements

Tk = a constant for the particular metal the winding is made from: 234.5°C for copper 225°C for aluminum

It is very difficult to determine actual winding temperature in the field, and, normally, this is not needed. You only need to do the above temperature corrections if you are going to compare resistances to factory values. Normally, only the phase resistances are compared to each other, and you do not need the winding temperature to compare individual windings.

You can compare winding resistances to factory values; change in these values can reveal serious problems. A suggested method to obtain an accurate temperature is outlined below. If a transformer has just been de-energized for testing, the winding will be cooler on the bottom than the top, and the winding hot spot will be hotter than the top oil temperature. What is needed is the average winding temperature, and it is important to get the temperature as accurate as possible for comparisons.

The most accurate method is to allow the transformer sit de-energized until temperatures are equalized. This test can reveal serious problems, so it's worth the effort.

Winding resistances are measured using a Wheatstone Bridge for values 1 ohm or above and using a micro-ohmmeter or Kelvin Bridge for values under 1 ohm. Multi-Amp (now AVO) makes a good instrument for these measurements which is quick and easy to use. Take readings from the top of each bushing to neutral for wye-connected windings and across each pair of bushings for delta-connected windings. If the neutral bushing is not available on wye-connected windings, you can take each one to ground (if the neutral is grounded), or take readings between pairs of bushings as if it were a delta winding. Be consistent each time so that a proper comparison can be made. The tap changer can also be changed from contact to contact, and the contact resistance can be checked. Keep accurate records and connection diagrams so that later measurements can be compared.

**4.7.2 Core Insulation Resistance and Inadvertent** Core Ground Test. Core insulation resistance and inadvertent core ground test is used if an additional core ground is suspected; this may be indicated by the DGA. Key gases to look for are ethane and/or ethylene and possibly methane. These gases may also be present if there is a poor connection at the bottom of a bushing or a bad tap changer contact. Therefore, this test is only necessary if the winding resistance test above shows all the connections and if tap changer contacts are in good condition.

The intentional core ground must be disconnected. This may be difficult, and some oil may have to be drained to accomplish this. On some transformers, core grounds are brought outside through insulated bushings and are easily accessed. A standard dc megohmmeter is then attached between the core ground lead (or the top of the core itself ) and the tank (ground). The megohmmeter is used to place a dc voltage between these points, and the resistance measured. A new transformer should read greater than 1,000 megohms. A service-aged transformer should read greater than 100 megohms. Ten to one-hundred megohms is indicative of deteriorating insulation between the core and ground. Less than 10 megohms is sufficient to cause destructive circulating currents and must be further investigated [19]. A solid core ground may read zero ohms; this, of course, causes destructive circulating currents also.

Some limited success has been obtained in "burning off" unintentional core grounds using a dc or ac current source. This is a risky operation, and the current may cause additional damage. The current source is normally limited to 40 to 50 amps maximum and should be increased slowly so as to use as little current as possible to accomplish the task. This should only be used as a last resort and then only with consultation from the manufacturer, if possible, and with others experienced in this task.

Table 17.—Transformer Test Summary Chart

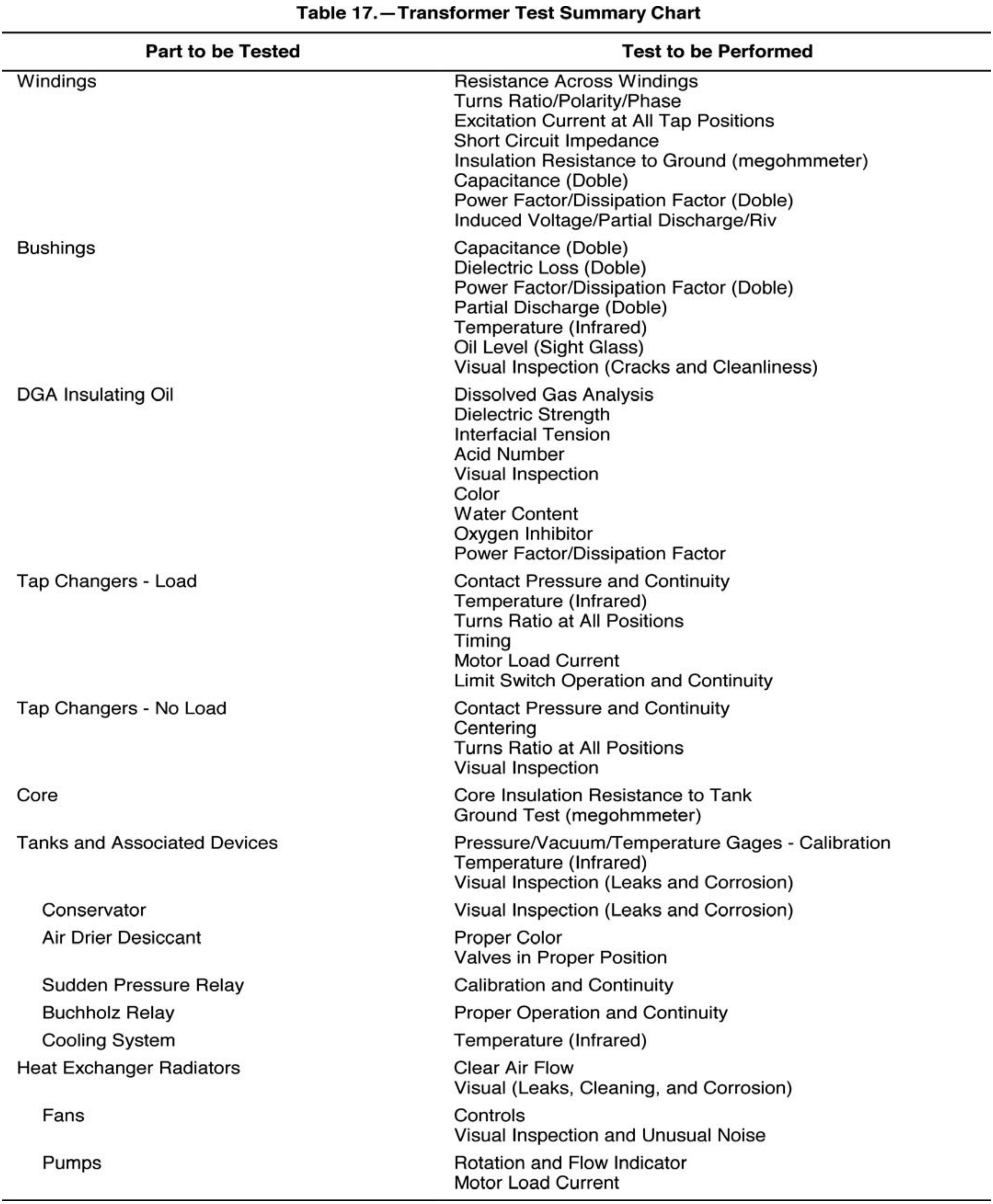


**Table 17.—Transformer Test Summary Chart**

| Part to be Tested | Test to be Performed |
|---|---|
| Windings | Resistance Across Windings<br>Turns Ratio/Polarity/Phase<br>Excitation Current at All Tap Positions<br>Short Circuit Impedance<br>Insulation Resistance to Ground (megohmmeter)<br>Capacitance (Doble)<br>Power Factor/Dissipation Factor (Doble)<br>Induced Voltage/Partial Discharge/Riv |
| Bushings | Capacitance (Doble)<br>Dielectric Loss (Doble)<br>Power Factor/Dissipation Factor (Doble)<br>Partial Discharge (Doble)<br>Temperature (Infrared)<br>Oil Level (Sight Glass)<br>Visual Inspection (Cracks and Cleanliness) |
| DGA Insulating Oil | Dissolved Gas Analysis<br>Dielectric Strength<br>Interfacial Tension<br>Acid Number<br>Visual Inspection<br>Color<br>Water Content<br>Oxygen Inhibitor<br>Power Factor/Dissipation Factor |
| Tap Changers - Load | Contact Pressure and Continuity<br>Temperature (Infrared)<br>Turns Ratio at All Positions<br>Timing<br>Motor Load Current<br>Limit Switch Operation and Continuity |
| Tap Changers - No Load | Contact Pressure and Continuity<br>Centering<br>Turns Ratio at All Positions<br>Visual Inspection |
| Core | Core Insulation Resistance to Tank<br>Ground Test (megohmmeter) |
| Tanks and Associated Devices | Pressure/Vacuum/Temperature Gages - Calibration<br>Temperature (Infrared)<br>Visual Inspection (Leaks and Corrosion) |
| Conservator | Visual Inspection (Leaks and Corrosion) |
| Air Drier Desiccant | Proper Color<br>Valves in Proper Position |
| Sudden Pressure Relay | Calibration and Continuity |
| Buchholz Relay | Proper Operation and Continuity |
| Cooling System | Temperature (Infrared) |
| Heat Exchanger Radiators | Clear Air Flow<br>Visual (Leaks, Cleaning, and Corrosion) |
| Fans | Controls<br>Visual Inspection and Unusual Noise |
| Pumps | Rotation and Flow Indicator<br>Motor Load Current |

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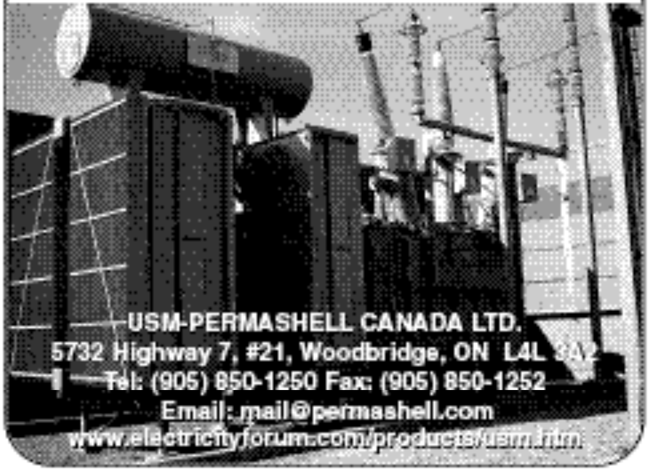

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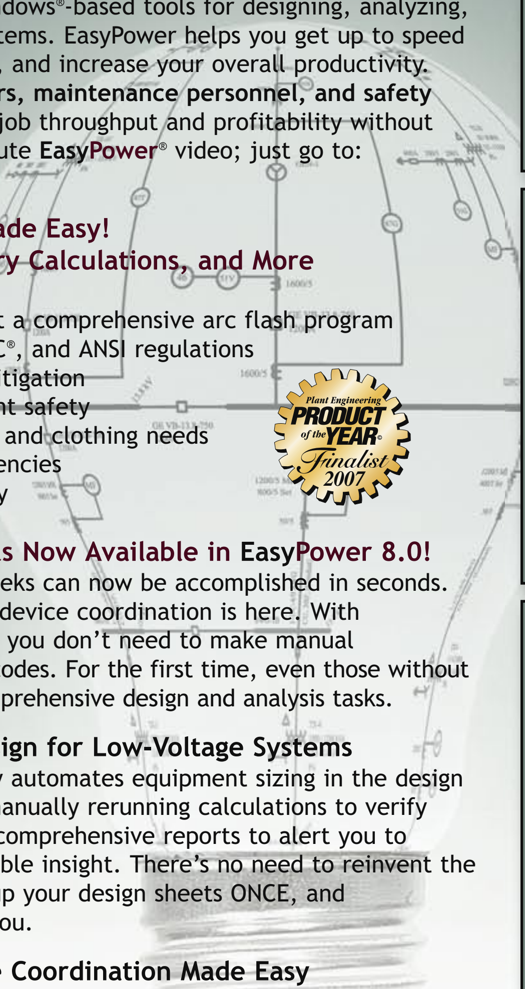

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